ENERGY TAX ACT OF 1977

HEARINGS

BEFORE THE

COMMITTEE ON FINANCE
UNITED STATES SENATE

NINETY-FIFTH CONGRESS

FIRST SESSION

ON

TITLE II of H.R. 8444

THE ENERGY TAX ACT OF 1977

PART 2

PUBLIC WITNESSES

AUGUST 10, 11, AND 12, 1977

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ENERGY TAX ACT OF 1977

WEDNESDAY, AUGUST 10, 1977

U.S. SENATE,
COMMITTEE ON FINANCE,
Washington, D.C.

The committee met, pursuant to notice, at 10 a.m. in room 2221 Dirksen Senate Office Building, Hon. Russell B. Long (chairman of the committee) presiding.

Present: Senators Long, Hathaway, Matsunaga, and Packwood.

The CHAIRMAN. The committee will come to order. At this point I would like to insert into the record a statement of Senator Hathaway.

STATEMENT OF SENATOR HATHAWAY

Mr. Chairman, I was sorry that I was unable to attend the first two days of testimony on the Energy Tax bill but I had made previous commitments to be in Maine working during the recess. I understand that Secretary of Energy Schlesinger and Secretary of the Treasury Blumenthal both made suggestions for revising and tightening the House-passed version of the Administration's energy plan.

I believe that the time is long overdue for this nation to adopt and implement a strong and viable National Energy Plan. It must consist of greater energy conservation, increased energy production from our known conventional sources and an expanded shift toward the inexhaustible and more exotic sources of energy.

A plan is fine if it encourages conservation where that conservation is possible. We must not blind ourselves, however, into believing that all conservation should be acomplished through price rationing. For many individuals, there is no present alternative to the automobile, and it's gasoline, for commuting to and from work. To penalize the farmers and loggers and ranchers because they have no alternative seems to me to be counterproductive. To raise the price of home heating oil and home heating propane and butane, where there is not a current alternative seems to me to be insensitive to the needs of the poor and the elderly.

On Monday, Secretary Schlesinger testified that: "The cost per million BTU in New England is three times the cost in the Southwest so that energy prices that New England has faced at the present time are very, very considerably higher than they are elsewhere in the country."A rebate of any increased cost of home heating oil is essential to the people of New England and I can assure this committee that I will oppose any measures to delete that aspect of the House-passed version.

I shall work with this Committee and the Administration to develop a strong and effective energy policy understanding that we must build into that plan compassion and a mechanism to offset the most severe burdens on those less able to deal with the higher costs of energy.

The plan must also encourage shifts from our current dependence on oil and natural gas into the inexhaustible and renewable assets of this earth. We must work to develop the solar and geothermal possibilities of nature. In Maine, we have a huge, renewable resource which has hardly been mentioned in the discussion of alternative energy sources—wood. Wood is the energy source that the people of the world have relied on longer than any other form of energy. I suspect that our genius and innovation can find altersative uses for many products that have been slighted in our search for the nation's energy needs.

A relative, fair, comprehensive and effective National Energy Plan is possible. It will take the resolve of the American people and its elected represestatives. However, I am confident that we will fashion the first steps in a blueprint for the future which will ensure the long-term security and stability of this Nation and will protect the lives and needs of those limited resources would otherwise be consumed by the higher costs of energy.

The CHAIRMAN. We are pleased to have this morning a panel consisting of Mr. Sidney L. Terry, vice president for public responsibility and consumer affairs of the Chrysler Corp.; Mr. Roger B. Smith, executive vice president, General Motors Corp.; and Mr. F. G. Secrest, executive vice president, Ford Motor Co.

Gentlemen, we are very happy to hear from you.

Mr. MULLER. Mr. Chairman, I am from the Chrysler office in Washington. Because of severe weather in Michigan, Mr. Terry has been delayed. He is en route, however, and I would be pleased, with your permission, to have the opportunity to read his statement.

I expect him to be here at any time.

The CHAIRMAN. However you want to do it gentlemen, that is fine.

Mr. MULLER. May I defer to Mr. Secrest and Mr. Smith?

The CHAIRMAN. If you would like to, go ahead.

STATEMENT OF FRED G. SECREST, EXECUTIVE VICE PRESIDENT, FORD MOTOR CO.

Mr. SECREST. I am Fred Secrest, executive vice president of Ford. We understand that the hearings this morning will focus primarily on the administration's proposal for tax and rebate plans on new automobiles. I do see that they have formally abandoned the rebate portion of the original proposal. That shows a commendable flexibility.

The CHAIRMAN. I think that they were sort of like the bartender who went back to talk to the proprietor and said, Bob Jones is out there. He would like to have a beer on credit. Shall I let him have the credit?

He said, has he had the beer? He said, yes, sir. He said, give them the credit.

I think they saw what the situation was, and made that wise move.

Mr. SECREST. Ford has met with the staff of the International Trade Commission in conjunction with their report to this committee on this proposal, and we testified before the ITC on July 6.

We agree with a number of the conclusions of the International Trade Commission study. They estimated that, under either a tax/rebate or a tax-only approach, domestic manufacturers would suffer a sales loss with accompanying reductions in industry employment compared with levels expected under the present Energy Policy and Conservation Act.

The study estimated that under the tax-only approach, the domestic industry's volume would go down by 140,000 units a year, which would lead to a job reduction of somewhere in the range of 50,000, and if the rebate were included, the losses would be greater than that.

ITC also noted that any reduction in volume of new automobile sales, "could tend to discourage conversion from older, less efficient, and more polluting full-size automobiles." Most importantly, ITC concluded that the tax/rebate proposal would not contribute meaningfully to the domestic industry's ability to meet the average fuel economy standards presently in the law.

In fact, the report stated that the proposal "could impair the ability of individual U.S. manufacturers to meet the average fuel economy standards under present law." According to ITC, imposition of tax/rebates could tend to reduce the flexibility of U.S. manufacturers to market a full line of passenger cars while still meeting average fuel economy standards because it would reduce a manufacturer's ability to use revenues from from sales of less fuel-efficient cars to reduce prices of smaller, more efficient models.

In general, these are the potential consequences Ford has repeatedly pointed out with respect to the tax/rebate proposals. We disagree strongly, however, with one conclusion of the ITC report—that the U.S. industry may not meet the standards in the present law.

Ford will meet the standards in the present law. The ITC report suggested that the economic consequences of not meetng the law under the present structure of penalties would be prohibitive "unless it becomes more profitable to sell inefficient automobiles and incur the penalty than to comply with present law."

Speaking for Ford, however, I must emphasize that there is no possibility of our choosing a law-breaking strategy, simply because it is unthinkable for a responsible publicly-held corporation to adopt such a strategy.

We will be under continuing surveillance by DOT and EPA that will monitor our achievements on that EPCA law and our future plans on a regular basis. It seems impossible, even if we wanted to, that we could adopt a strategy designed to break the law and pay the penalties.

Achievement of the presently mandated standards will result in almost a 100-percent improvement in the fuel economy of new 1985 model cars, compared with 1974 models. Further, the absolute gasoline consumption by all passenger cars in use in 1985 will be reduced more than 18 percent from last year's levels, according to a recent report by DOT. Incidentally, automobiles are the only major energy-consuming sector for which a decline seems likely.

Only last month, the Department of Transportation established a schedule of 1981–84 fuel economy standards—22 miles per gallon in 1981; 24 miles per gallon in 1982, 26 miles per gallon in 1983 and 27 miles per gallon in 1984—which, in DOT's judgment, represent the maximum feasible standards, and which are at levels significantly higher than those first proposed by DOT.

In enacting the Energy Policy and Conservation Act, Congress set the industry a 10-year task. Ford will commit more than $8 billion between now and 1985 to new technology, new materials, and new generations of smaller and lighter vehicles to meet these standards and still serve the full range of the American public's transportation needs.

Of course, bringing new technology into production on rigid timetables always involves risk. Each product action based on new technology has its own confidence measure—40 percent, 60 percent, seldom 100 percent. Some actions are almost certain to fall short by small increments of either fuel efficiency, timing or both.

By the same token, others may work out better than our engineers have predicted. We expect that such successes and failures will tend to balance out.

In order to insure that we meet the standards, however, we will have contingency plans, involving marketing, pricing and production-schedule changes, ready to implement if corrective action is needed. Under such a strategy, any technical shortfalls would have a relatively minor effect on the overall fleet average—which after all is the ultimate objective—and employment disruptions should be minimized.

The tax/rebate program, on the other hand, attempts to insure attainment of the fuel-economy standards through a single set of numbers, developed years in advance and for the entire industry. Obviously such a program is too rigid to be well-suited to the particular technical or consumer-response problems that individual producers may face during the next 8 years.

In fact, all of the additional new car measures under consideration by Congress would put the basic rationale for fleet average fuel economy standards into jeopardy. Based on developments of the past 3 months, it seems probable that the rebate part of the administration's proposal will be rejected, because of concerns over either exporting jobs or violating international trade agreements.

A tax alone, superimposed on the present standards, would penalize the full-range manufacturer, such as Ford, who attempts to provide a full array of products, some of which might be taxed. Another manufacturer, with a narrower range of products and the same corporate average fuel economy might not pay any tax.

In contrast to a theory that seem to underlie some of the administration reasoning, many families that own one large car use less gasoline than families that own two or more smaller cars. The administration proposal would base taxes based on the type of car, rather than on the amount of gasoline that the car consumes.

Contrary to the public image associated with the term "gasoline guzzler," it is the standard family car on which most of the proposed taxes would be levied, not the luxury cars which account for less than 5 percent of the market. To the extent that the proposed taxes have an effect on price, they would be paid largely by the buyers of family-size cars. As noted in the ITC report, such a tax is likely to induce those people who need family-size cars to retain their present less-efficient cars beyond normal trade-in cycles which, in turn, would reduce sales and employment.

The administration proposal is punitive in its tax levels, especially because it would go into effect before manufacturers could mitigate or eliminate the taxes by technological changes. We are beginning certification of 1979 models now, and there is little time left to make major changes even for 1980.

The tax measure adopted by the House Ways and Means Committee and subsequently passed by the House is less punitive and takes into account some of the inequities that could be associated with new taxes in the near term. Nevertheless, Ford believes that the tax proposal passed by the House is unnecessary and will not contribute to achievement of the goals set by Congress 2 years ago.

The Senate Energy and Natural Resources Committee has adopted yet another proposal to be superimposed on existing law. It would set minimum fuel-efficiency standards, beginning in 1980, which would effectively prohibit the production of new cars below those minimums. As Ford testified before that committee on August 1, our present product plans include production of no passenger car models, as currently defined, that would fall below the fuel economy minimums adopted by that committee.

The question could be raised, if you are not planning any vehicles that are affected, because of the risk inherent in new technology and because of the variability in testing for fuel economy, there is obviously a possibility that some cars may fall below the minimum, even though we have no plans for them to do so. Because of the timing for final fuel-economy testing for new cars, we may not know that the manufacture of a certain model was prohibited until new model production was about to begin.

Until and unless we could effect a change that would bring the affected models back above the minimum, some operations can be shut down even though the corporate fuel-economy average was in full compliance with the law.

We would also like to point out that there is no evidence to suggest that those future passenger cars which might fall below the minimum would be primarily luxury cars. In the case of Ford's products, the models closest to the minimums may often be those family car lines where low purchase price is a key motive and which, therefore, would not represent an ideal initial testing ground for expensive, new fuel-saving technology.

With respect to doubling the penalties in the present law, we believe such an action is unnecessary in view of the magnitude of the present penalties and our commitment to meet the law. A shortfall of 1 mile per gallon under present law would result in a penalty of about $150 million for Ford—equivalent to $300 million before taxes. And, as previously stated, we do not consider a conscious strategy of noncompliance a practical alternative.

In our view, none of these proposals will result in measurable fuel savings. This conclusion appears to be endorsed by a number of Government-sponsored studies—for example, former FEA economist James Sweeney, and the Office of Technology Assessment, among others, have stated that the tax/rebate proposals will have little or no impact on fuel consumption.

The only studies we have seen that forecast fuel savings were done by the ITC committee and the Congressional Budget Office. Both studies were based on the erroneous assumption that manufacturers would break the law and plan to miss the standards. Even if the assumptions were correct, the improvement in new-car fleet average fuel economy is projected by ITC at no more than .2 mile per gallon in 1985.

In summary, if the goal of Congress is directed at fuel conservation, some of these measures is necessary to insure the major fuel savings that will be achieved by the present law. We plan to meet these standards and are prepared to take whatever steps may prove necessary to achieve them.

Additionally, the tax, rebate and minimum-standard proposals may well have a negative fuel-efficiency impact, by impairing our ability to meet the standards without severely restricting the types of vehicles available to the consumer.

The present law takes effect just this fall, and it certainly appears premature to conclude that additional legislative assistance is required to attain the goals set forth by this law. We strongly urge that Congress give the 1975 law a chance to work before superimposing an added set of penalties and rules.

I would like to, if I may, Mr. Chairman, offer just one or two brief comments that are not in my prepared statement, dealing with the subject of trucks, which I see was raised by Secretary Schlesinger in his discussions with you on Monday.

He has apparently suggested that the tax exemption on trucks in the House bill be deleted. There is not a truck exemption in the bill passed by the House. In that bill, trucks that are not designed primarily to carry property and that have a cargo capacity, of less than 1,000 pounds are subject to the excise tax.

The only trucks that are excluded are essentially those which, by definition, are principally designed to carry a substantial tonnage of cargo.

Second, I would suggest close examination of data cited, I believe, by the Secretary purporting to show that 53 percent of light-duty truck use is for personal transportation and recreation. In our judgment, and we have done a great deal of market surveying on this point, the vast majority of trucks are purchased primarily for cargo needs, for which passenger cars are generally unsuitable. Of course, many of these trucks are also used for personal transportation. The farm pickup today is a pretty classy and respectable and comfortable vehicle in which farmers and other people can drive to church as well as haul goods around, but the energy efficiency of that truck has to be measured against the job that it is built to do, not against a far different task that is assigned to passenger cars.

The Department of Transportation has recognized this obvious inherent differential when it recently set a 1979 model fleet average fuel efficiency standard of 17.2 mpg for light trucks.

The EPCA directed the Department to put these light truck standards at the maximum feasible level. The Department set them at 17.2, almost 2 mpg lower than the standards that applied to passenger cars in the same year. So clearly, the Government—or at least DOT—has recognized that trucks and cars are different and they cannot be treated the same way.

That concludes my statement, Mr. Chairman.

The CHAIRMAN. Suppose we hear from Mr. Smith.

STATEMENT OF ROGER B. SMITH, EXECUTIVE VICE PRESIDENT, GENERAL MOTORS CORP.

Mr. SMITH. Mr. Chairman and members of the Senate Finance Committee, I am Roger B. Smith, executive vice president of General Motors Corp. We appreciate the opportunity to present General Motors' views on the tax aspects of the National Energy Act. Because of the brief time available for the oral presentation of views, my statement will be confined to the transportation-related provisions of the proposed act.

There are many short- and long-term implications of any new energy legislation. We would urge that the Congress take sufficient time to study all the ramifications of various proposals. Clearly, adequate time was not available to the administration to prepare its legislative proposals.

We are hopeful that such shortcomings will be corrected by Congress.

It is well to bear in mind the objectives President Carter announced in connection with his anti-inflation policy: "To create jobs, stabilize prices, and promote general economic development with fairness and equity for all." GM supports these objectives and commends the President for recognizing their importance. However, there are some aspects of the President's energy program that conflict with those economic goals.

The new car excise tax/rebate scheme proposed by the administration and related proposals assume that additional government interventions are needed to manipulate the buying choices of the American public and to insure that auto manufacturers will meet the mandated fuel economy standards. These assumptions are inconsistent with any thoughtful consideration of the situation.

Such proposals are not expected to make any significant contribution to energy conservation, but will reduce auto sales and add to unemployment.

Absolute declines in auto gasoline consumption can be anticipated because of fuel economy improvements of new cars in the showrooms and on the drawing boards. GM has been the leader in making these fuel-economy gains.

Our 1977 new car fuel-economy average has increased 48 percent since the 1974 model year and our 1978 average is expected to be almost 60 percent above 1974, or about 19 mpg.

We expect to continue to make fuel economy gains, and GM is committed to doing everything possible to achieve the 1985 target of 27.5 mpg with cars that meet the needs of the American people. Figure 1 illustrates the fuel economy gains made to date in GM cars and the fuel economy standards for future years.

The CHAIRMAN. All right.

Those figures are miles per gallon that you expect the average car to get, are they?

Mr. SMITH. Yes, sir.

The CHAIRMAN. I wish you would show me how that chart works.

Mr. SMITH. Yes, sir.

The part marked "History" is actually from the EPA's certification of our fleet-rated average. Beyond that, we have set targets that you can see are 1 mile per gallon above what the energy law requires, on up through the year 1980, and these are based on EPA data.

The CHAIRMAN. Please proceed, sir.

Mr. SMITH. We believe that GM's major challenge is to build a line of products that will meet these production weighted fuel economy standards and, at the same time, will serve customers' needs better than those cars currently on the road.

The success of any gasoline conservation program that focuses entirely on new cars will yield results only as rapidly as the existing fleet of cars is replaced by more efficient cars being produced now and planned for the future.

The proposed excise tax/rebate scheme reflects an extraordinarily simplistic notion of how the automobile market works, of the barter element in almost all new car transactions and of choices that are and will continue to be available to American car buyers. Its impact will fall most heavily on middle and lower income families who rely on a single five- or six-passenger car to fill their transportation needs.

Moreover, an excise tax which raises new car prices will be quickly reflected in higher prices of suitable used cars which historically have filled the transportation needs of many single-car families. Finally, by increasing the value of less efficient, older cars, an economic incentive is provided for extending, through added maintenance, their useful lives.

The most fuel efficient cars it is possible to produce will make no contribution to reducing gasoline consumption unless they are purchased to replace less efficient vehicles in the existing fleet. To the extent that Congress imposes additional restrictions on our flexibility to meet market demands, the fleet will not be replaced and our fuel conservation goals will not be met.

Excess fuel consumption would not be the only cost of this proposal. The International Trade Commission, in its report to the Senate Finance Committee, estimates a loss of 140,000 domestic car sales in 1985 under the President's tax proposal and a loss of 330,000 domestic car sales under the combined tax/rebate proposal.

As the ITC report indicates, the combined excise tax/rebate scheme would result in a loss of 23,000 jobs in the auto industry in 1985. Based on the Bureau of Labor Statistics estimates, there would be an additional loss of 66,000 jobs in other supporting industries throughout the country.

The reduction of almost 90,000 jobs in the country as a result of the administration's proposals is difficult to justify on the basis of energy conservation. The ITC report, using an analysis procedure developed for the administration, estimates that 1985 auto gasoline consumption would be reduced only about .05 million barrels per day—that is about one-half barrel per day for every displaced worker.

That means that U.S. oil import costs would be reduced just over $3,000 per year for every worker displaced. Given the economic losses and hardships that would be placed on their families, it would be difficult to explain to these workers how such a policy can be justified in the name of energy conservation.

The rebate aspect of the administration's proposal would create possible violations of the General Agreement on Tariffs and Trade if imports are excluded. If imports were to receive rebates, it would mean that American buyers of U.S.-produced cars would be subsidizing the sale of imported cars through revenue generated by the excise tax.

The confusing situation that would result from the rebate scheme would be disruptive to present owners of smaller cars because of loss of resale value, to new car buyers, and to competitive conditions in the sale of motor vehicles.

Thus, the rebate scheme would be rejected.

The House of Representatives has rejected the proposed rebates in the administration's tax/rebate scheme, and the fuel inefficiency tax proposal also was substantially modified. While these changes do, of course, represent improvements from our point of view, the penalty tax schedule in the House-passed bill would still discourage the replacement of cars in the fleet.

Adding only an excise tax on family size cars does not eliminate the economic disruptions since the sale of these cars would be reduced and job losses would occur. Gasoline consumption would be changed only marginally based on the ITC analysis.

Likewise, a DOT report stated:

> . . . neither an excise tax-caused mix shift or any mix shift short of dramatic 50-percent changes has a significant . . . impact on fuel efficiency.

Tax policies designed to manipulate consumers' purchase decisions create economic risks, offer very little in gasoline savings—and even marginal savings could be reversed if retention of older cars results.

Meanwhile, the Senate Energy and Natural Resources Committee has adopted an amendment to the energy bill that would double the penalties on manufacturers who fail to meet the production-weighted fuel economy standards. The amendment also would prohibit the production or sale of cars that do not meet specified minimum fuel economy standards, even though the affected manufacturer might otherwise meet the fleet average requirements of the existing law.

There is no indication of a need for such further interference by the Government in the automotive market. There is no question that consumer preferences have substantially changed the mix of cars purchased over the past several years.

For example, in the 1968 model year, only 25 percent of new car sales were in the small-car category. In 1976, almost 50 percent of total new car sales were small cars.

This chart we have here illustrates this shift in market mix that has resulted from changes in demand without Government actions. At the same time these shifts in market shares are occurring, great changes are being made in our products within market classes.

In the 1977 model year, more than 700 pounds were taken out of our full-size cars. Similar resizing is taking place with our intermediate cars in the 1978 model year that is about to begin. As a result of these and additional product changes in later model years, the average inertia weight of GM cars is expected to average about 3,100 pounds by 1985, as compared to 4,500 pounds in 1975. This change in average inertia weight is illustrated by figure III.

In summary, we believe there are persuasive reasons for rejecting the excise tax/rebate scheme. In the already existing mandatory fuel economy standards, the industry has more than adequate incentive to adapt its products to the goal of oil conservation. Moreover, it has now, as it always had, the incentive of self-interest to accelerate as rapidly as possible the replacement of the existing fleet on the road.

President Carter has announced his objective to reduce the Nation's overall gasoline consumption by 10 percent by 1985. If the auto industry succeeds in its objective of producing a marketable product line, gasoline used by passenger cars will be reduced by more than 14 percent between 1977 and 1985 (figure IV). I can assure the committee of General Motors' determination to do its part in making this goal a reality.

[The charts referred to by Mr. Smith follow:]

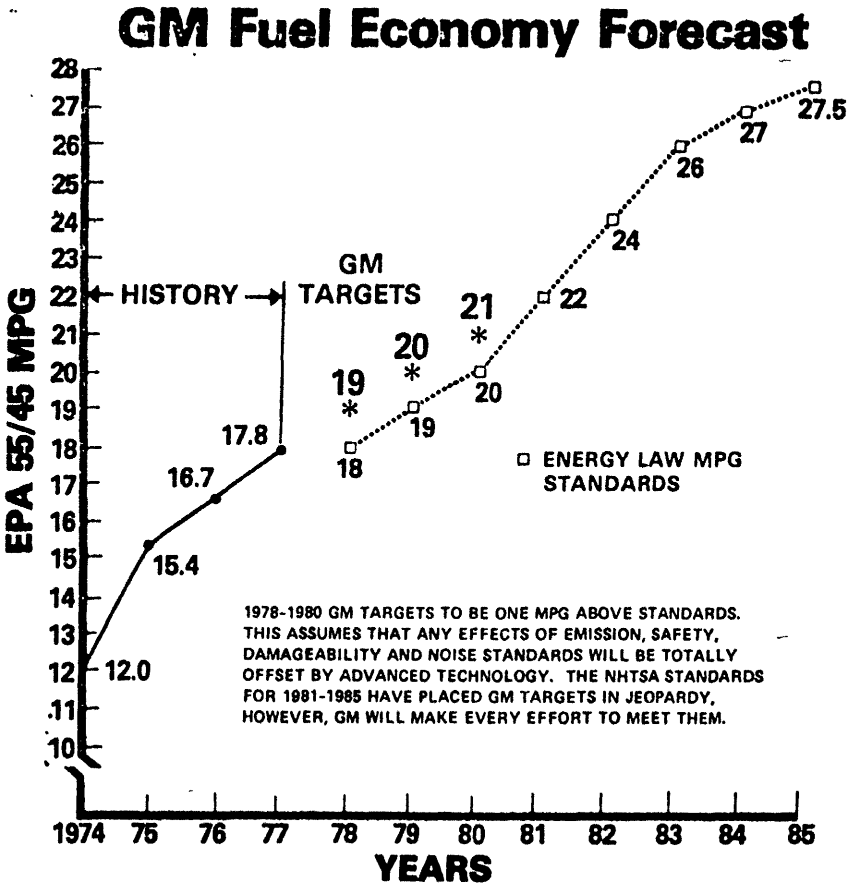

FIGURE I

GM - 8/10/77

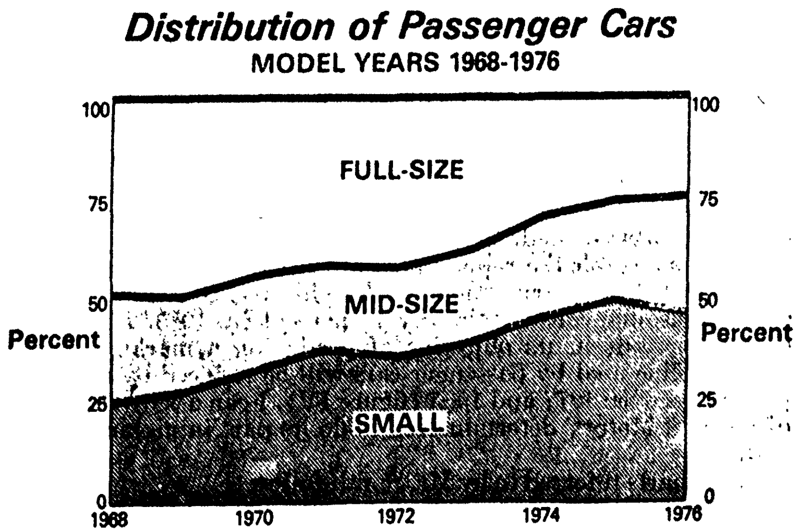

FIGURE II

Projected GM Average Inertia Weight

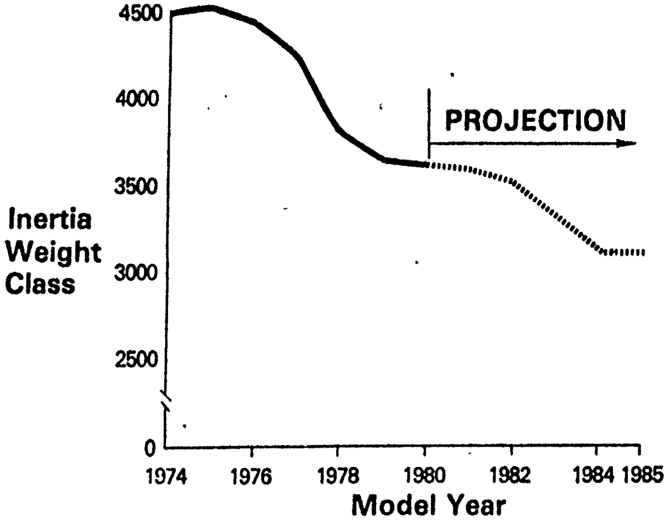

FIGURE III

Estimated Industry Fuel Consumption

BY GAS POWERED AUTOMOBILES

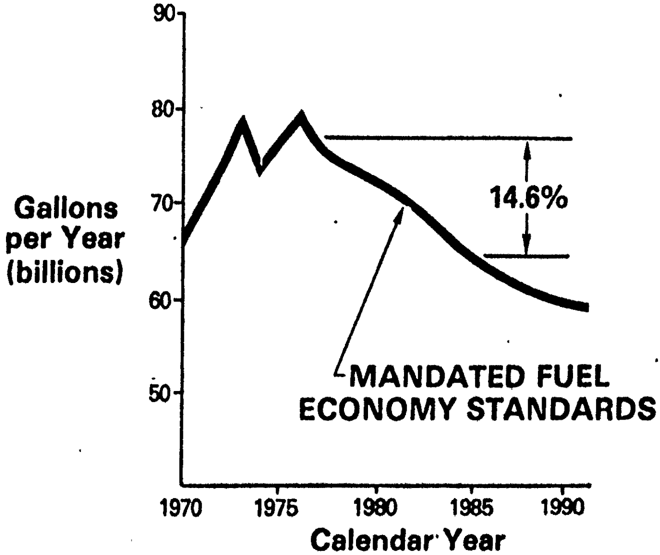

FIGURE IV

The CHAIRMAN. Thank you very much, sir.

I suppose you should read Mr. Terry's statement, so that we will have heard all three statements.

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STATEMENT OF SIDNEY L. TERRY, VICE PRESIDENT, PUBLIC RESPONSIBILITY AND CONSUMER AFFAIRS, CHRYSLER CORP., PRESENTED BY RICHARD J. MULLER, DIRECTOR, PUBLIC RELATIONS, WASHINGTON OFFICE, CHRYSLER CORP.

Mr. MULLER. Thank you, Mr. Chairman.

My name is Richard Muller, director of public relations, Washington office, and I am happy to deliver the remarks of Sidney L. Terry, vice president of public responsibility and consumer affairs.

Standards enacted by Congress in 1975 require a 100-percent fuel economy improvement for new cars within 10 years. They enable the country to meet the President's automobile energy conservation goals. Even with the projected 20-percent increase in total cars on the road by 1985, current law will reduce total gasoline consumption by 10 to 17 percent.

We, at Chrysler, have made our commitment to meet the requirements of law. We are well along on a multi-billion-dollar program to redesign every vehicle we now make, and to introduce new lines of lighter, more fuel-efficient passenger cars. Our 1985 vehicles will be about 25 percent lighter on the average than 1974 vehicles. They will have new transaxles, new engines and transmissions, and extensive electronic controls for greater efficiency and fuel economy.

There is no need for an additional system of taxes or other actions to be imposed on top of the fuel economy standards already in place. The so-called gas-guzzler tax or a mandatory minimum miles per gallon standard could do a great deal of harm. They would disrupt an otherwise free market, restrict the consumer's choice, and accomplish little or nothing in the way of energy conservation.

Today, I would like to put those taxes in better perspective, and call them what they really are—punitive tax on family cars.

In spite of all the phony rhetoric about monstrous gas guzzlers, the fact remains that the system of taxes reported out by the House Ways and Means Committee would, in 1985, levy a fine of more than $500 on a family of six who buys a six-passenger car that averages 22 miles per gallon. It is clear that the tax would fall heaviest on those who can afford it least—individuals and large families in the lower income brackets who can afford to buy only one vehicle.

More than a third of all new car-buying households own only one vehicle. Nearly 22 million households include 5 or more people. For decades to come we will need vehicles that can hold five or six people comfortably, with room for their packages and luggage. We will need vehicles with sufficient power to pull a trailer, tow a boat, or carry a load.

California, which is the Nation's largest car market, has a special problem. Since California has tighter emissions standards than the other 49 States, the average new car sold in California, including both domestic and foreign cars, already gets about 12 percent worse fuel economy than the average new car in the other 49 States.

If California emissions standards continue to be more stringent—and all indications are that they will continue to be—then we could incur an additional penalty of as much as 2 miles per gallon.

A family-car tax would severely penalize California consumers and consumers in any other States which might adopt the California standards, as provided for in the recent amendments to the Clean Air Act. A bottom-line cutoff fuel economy standard could be even worse in that it might effectively outlaw some family-size cars altogether in all those States.

The wisdom of the present fuel economy law is that it is based on fleet averages. That gives the manufacturer the freedom to produce a total fleet that meets a variety of needs of American consumers. In other words, in 1985, we can produce a mix of family-size cars and California cars that may get as little as 19 or 20 miles per gallon. And yet, because we will also have vehicles that exceed the standard by a wide margin, our total fleet will average 27.5 miles per gallon.

There is no need for the family-car taxes, bottom-line cutoffs, or the rebates originally proposed by the administration. Evidence shows that the family-car tax will provide little or no benefit beyond the law on the books, which is already sufficient to meet our national goals. A report by the International Trade Commission concluded that the family-car tax would increase the competitive edge of foreign cars.

A recent Chase Econometrics study shows that with the tax and rebate proposal added on top of the present law, the fuel economy of U.S. cars would improve by only one-tenth of a mile per gallon in 1985. The tax without the rebate would achieve even less of an improvement.

In fact, the Chase estimates may be optimistic. If family-size cars are discouraged, carowners may well choose to keep their older, family-size models, and the penalty in wasted fuel would exceed any theoretical gains from the additional tax itself.

All the auto companies are now in the process of redesigning their cars to meet the fuel economy averages required by law. Each company is following its own plan and timetable as it resizes its line of cars.

If a company fails to meet the standards, the penalty is a non-tax-deductible fine of $5 for each one-tenth of a mile under the standard—times the total number of cars in the fleet. At a charge of $50 per mile per gallon per car, this would result in a $100 million after-tax fine for Chrysler for missing the standard by 1 mile per gallon. You can see that we are talking about enormous penalties.

In light of the severity of the penalty on the books today, no auto manufacturer is ever going to plan a model mix that falls short of the required fuel economy. It will not make any real difference whether Congress increases the penalty. We are not going to break the law. We are not going to miss the average fleet fuel economy requirement.

We need no disincentives from family-car taxes, bottom-line cutoff standards, increased penalties, or any other last minute schemes that would throw off our current progress in meeting the law already on the books. Taxes on cars making over 20 miles per gallon, and bottom-line cutoff standards in particular, would unnecessarily penalize California consumers, handicap law enforcement agencies, and limit our ability to plan marketable future products.

The law on the books is sufficient. We intend to comply with it fully. We urge Congress to reject other unnecessary and counter-productive proposals.

The CHAIRMAN. Senator Packwood?

Senator PACKWOOD. Tell me what the Senate Energy Committee did exactly in terms of banning cars with poor gas mileage. What did they ban?

Mr. SMITH. Do you mean in terms of specific car models? Is that what your question is?

Senator PACKWOOD. Each of your statements make reference to Energy Committee action. I am not sure what they did. Could you explain what they did?

Mr. SECREST. The bill that was passed by that committee, which I have before me, although I am not sure I can interpret it perfectly, had two provisions. The first was to establish a set of miles per gallon numbers starting in 1980 at 16 miles per gallon and rising 1 mile per gallon per year to a level of 21 miles per gallon in 1985.

Senator PACKWOOD. Is that below the Department of Transportation figures?

Mr. SECREST. Yes. The center points on the existing law, the EPCA law, which the fleet must average are 20 miles per gallon in 1980 and 27.5 miles per gallon in 1985.

So the Energy Committee amendment to the law would not repeal those numbers, but would establish minimums of 16 miles per gallon in 1980 rising to 21 miles per gallon in 1985.

No car could be produced——

Senator PACKWOOD. Below those standards?

Mr. SECREST. Below.

Senator PACKWOOD. No more fleet average?

Mr. SECREST. The fleet average would still prevail. You would still have to average, in 1980, 20 miles per gallon. If you had a 15.9-mile-per-gallon car, even though your average was 20 or 21, you could not produce the 15.9 car.

I should state that it is not an absolute prohibition. It is a fine of $10,000 per copy, which effectively is an absolute prohibition.

Senator PACKWOOD. The fleet average in that case is out. You cannot produce a number of cars below and above. They are giving you a different fleet average.

Mr. SECREST. You still have to meet 20.

Senator PACKWOOD. I understand that. You could not produce anything below 16.

Mr. SECREST. That is correct, for 1984.

They also doubled the amount of the penalty for noncompliance with the average. In Ford's case, $150 million after taxes for a 1-mile-per-gallon shortfall would be $300 million, after taxes.

Senator PACKWOOD. You will meet those standards?

Mr. SECREST. Yes.

That is our intention, to meet the standards.

Senator PACKWOOD. You could meet the standards set down by the Senate Energy Committee. You would simply not produce cars that fall below a certain level.

Mr. SECREST. That is right. That would be our plan.

Senator PACKWOOD. What it would mean is that you would be prepared to cut off a fair number of family cars, if you could not squeeze them into that mileage; you would cut them off.

Mr. SECREST. That is right. You have only two alternatives: you must get them above the minimum, or you must drop them.

The Ford plans at the moment call for no production of cars that would be below those minimums. Two things can happen, as I tried to indicate in my testimony.

First, you can miss, and if you miss under a fleet average concept, you can offset it with successes elsewhere.

Senator PACKWOOD. Tell me what you said again, Ford plans to produce no cars that would fall below the Senate Energy Committee minimum?

Mr. SECREST. That is correct.

Senator PACKWOOD. Assuming you meet what you are hoping to meet, those Senate energy standards will not affect you.

Mr. SECREST. That is right. That is what we testified.

Senator PACKWOOD. There is no guarantee that you can make it; but you are hoping that you can make it?

Mr. SECREST. That is right, even though there would probably be some misses. Under the present law, the misses can be balanced out with the more successful efforts, those that turn out better than we presently can forecast.

Senator PACKWOOD. Tell me why the bill that passed the House unduly favors imports?

Mr. SECREST. Well, if there is to be a tax applicable in addition to the fleet average standards that everybody must meet, a tax applicable to vehicles getting less than some stated number of miles per gallon, because the imports for decades have concentrated solely in the small car area, very few, if any, of their cars would be subject to the tax.

To the extent that there are any taxes that have to be paid that raise the prices of certain cars, if it has any economic impact at all, it would tend to divert some customers away from domestic cars toward imports. That is what the ITC study seemed to conclude.

Senator PACKWOOD. The answer is not that they produce any better cars, but just that they produce a certain line of cars that have slightly higher mileage?

Mr. SECREST. That is correct.

Senator PACKWOOD. On page 2 of Mr. Terry's statement, he says, "For decades to come we'll need vehicles that can hold five or six people comfortably, with room for their packages and luggage." We cannot produce a car then that meets that criteria at the mileage standards in the House bill, or we cannot produce it without a tax. Which?

Mr. MULLER. I am sorry, Mr. Packwood. I did not hear the last part.

Senator PACKWOOD. We cannot produce a car that will hold five to six people comfortably with room for their packages and luggage, or, we cannot produce it and have it make a high enough standard in mileage to avoid this tax.

Mr. MULLER. The latter is the case. Also, we indicate on page 3, in this case referring to the Metzenbaum amendment passed by the Senate Energy Committee, the flexibility of producing a mix of family-size cars, we would get less than a mandatory minimum but still meet fleet average because you would be building enough cars to balance out.

Senator PACKWOOD. I understand how you can meet the fleet average. But if you are stuck with the Senate Energy Committee standard, can you produce a family car, the six-passenger car that can meet that standard?

Mr. MULLER. I am going to have to defer to Mr. Terry when he arrives to commit to an answer to that.

Senator PACKWOOD. I pose it to the other witnesses. Can you produce a car that can meet the minimum standards set by the Energy Committee bill that will comfortably hold five to six people?

Mr. SMITH. I think that that is what we are all striving to do. The cars that we have in effect right now, if you look and see them, the Chevettes and the foreign cars are mostly lighter cars, smaller cars, that normally carry four people comfortably. What we are striving to get to is to get that in a six-passenger vehicle that will be designed for carrying a load, a family station wagon that will carry, or tow a trailer, boat trailer, or move goods, for people who only have one car.

The challenge of what we face is doing this in terms that we do not deprive these people of that type of automobile, as we do not want to cut out the family who can only have one car that can serve all the purposes.

With current technology, most cars that get 27.5 miles per gallon-plus on these tests are not really suitable for carrying six passengers. Most of them are four-passenger vehicles. Certainly most of them do not have the power in them or the braking capacity to move a trailer or a boat, or something like that.

That is our challenge, to get there without cutting these people off without a vehicle.

Obviously when you put taxes and standards and prohibitions on these types of vehicles, it does impact. None of us have plans to produce vehicles below the standards. It does not make sense.

Our challenge is to meet the standards with vehicles that can handle six people. That is why we think that the average is so important.

We can get to the Nation's fuel economy goals based on our fleet average. The more we restrict that average in terms of lopping off one end or the other end, the more difficult it is for us to market a full range of vehicles.

After all, the country's fuel economy conservation will be determined by the average.

Senator PACKWOOD. I understand that. I also understand the argument you are making about maybe people will not trade in their cars if they cannot haul a boat.

I want to get back to the car which holds five or six people comfortably. I am not knowledgeable about new cars. I have not bought a new car in 10 years. I have a couple of used cars that are 4 or 5 years old.

The new Volkswagen buses hold six people comfortably. What do they get, in terms of mileage?

Mr. SMITH. The Volkswagen—I am reading now from the 1977 EPA gas mileage guide—the Volkswagen bus or campmobile, as I see it here, gets a fuel economy of 21 or 23, depending on whether it is automatic or manual.

Senator PACKWOOD. Is that what is called the Volkswagen bus?

Mr. SMITH. They have three names here. I assume that any one of these are about the same type of vehicle, depending on how they are outfitted.

Senator PACKWOOD. What page are you on?

Mr. SMITH. Page 28.

Senator PACKWOOD. I see what you are saying; 28 on the highway, 23 in the city for that campmobile.

I am not necessarily criticizing, but I find it hard to believe that a car cannot be made that can get 27.5 miles at a minimum and hold six people comfortably. I do not know if it would tow a boat or trailer or not.

Mr. SMITH. It is possible to increase mileage by sacrificing performance but there comes a certain point when the vehicle just becomes unacceptable in terms of not being able to climb a hill, for example, and there is a safety factor there, too, in the car's ability to pass other cars.

We think, as I say, the real challenge for us is to provide an acceptable vehicle that people can drive and be safe and meet these fuel economies. We are all dedicated to do that based on the average fuel economy. As we say, that is going to be the important thing for the country.

What we do not want to see is anything that would impact severely on large families, who, in most cases, are the people who are least likely to be able to afford a higher priced vehicle.

Senator PACKWOOD. I sympathize with that. I do not want to inconvenience them. Certainly I do not want to deprive them of any car that they need, period.

If what you are saying is simply we will not be able to make them, then they will be out of luck. I just want to make sure in my own mind that what you are saying is accurate, that a car cannot be produced to get 27.5 miles and haul comfortably, short of taking off every conceivable accessory on it that you might take off.

I do not know what happens if you take off the air conditioning and the automatic transmission and almost everything else, where you could make it or not or, if you could, whether we would want to do it.

Mr. SMITH. The impact of accessories on fuel economy in the present stage of the development is really grossly overstated. I do not think that is going to be where the great gains in fuel economy are. They will not be there. They will be made through technological developments.

We are working on lock-up clutches, additional gears in the automatic transmission——

Senator PACKWOOD. What is a lock-up clutch?

Mr. SMITH. A clutch that eliminates any slippage between the engine and the differential. In the present automobiles, for years, to avoid a rough ride, have very limited slip between the engine and the rear differential.

What we intend to do in our forward program is to have to eliminate that and get mileage gains. I think that is where our big mileage gains are and downsizing the car, taking 700 pounds off the car, keeping the same interior space. We think great gains can be made.

When you do that, you do not take anything away from the people. You give them the same thing they had before in terms of package size for themselves, but you do improve their fuel economy.

We are dedicated to doing that.

Senator PACKWOOD. Thank you.

I have no further questions, Mr. Chairman.

The CHAIRMAN. Are your lighter cars going to have power brakes?

Mr. SMITH. Some will, some will not.

As you get down to the lighter cars, obviously your need for power brakes is less, depending, of course—I think there will always be some market for them, Senator. For some people, I do not want to single out any particular people, but some people will find them a convenience and a safety benefit in driving.

We keep the brake pressures to a specified minimum. There are still some people who I think will still find them attractive.

Again, their impact on fuel economy will be almost lost in the overall average.

The CHAIRMAN. One of the saddest days of my life was the day I bought an automobile with the ordinary crank-up windows, when my little girls had their hearts set on pushbutton windows. When I came home, they were so disappointed. I was in the doghouse, a pinchpenny bum for a month. It seemed to me that they were a waste of money, they were four more things to have repaired and more expensive to repair, but that is not the way my little daughters looked at it. They wanted to have pushbutton windows jumping up and down.

I still think that pushbutton windows are a waste of money and just four more things to have fixed, and yet your company designs a car so that it is necessary to have the air-conditioning option. The old-fashioned device for which you push a little knob works such that the vent opens and the wind blows on you while you are driving down the road. With the vent system, it is only on a hot day when you need the air-conditioning.

This design has been eliminated; the wind does not even circulate the way it is now designed. Curved glass windows slide up. The frame has been taken off the door and, in a lot of these cars anybody with a screwdriver can break into your car without any difficulty at all—you do not even need a screwdriver in breaking into the car. The glass is pulled off the track, and if one can ever get it repaired, it is a miracle.

When are we going to get back to having some practical type automobiles in which, instead of hauling around a bunch of motors to do something, one can operate the windows by hand without any real difficulty? That would save a lot of money, and it would result in a more practical car.

Mr. SMITH. You will be happy to know, Senator, that our new 1977 full-sized cars have the full door frames that do not have the frameless glass in them.

The CHAIRMAN. That is a step forward.

Mr. SMITH. We believe that.

I would say this. We believe we have to offer the people and the American market the full range of optional accessories that they can have and want. We do not want anybody to have to buy a foreign car to get something they can't get on an American car.

So our goal is to meet the competition from our friendly companies on either side, and offer the American people the greatest range of options. They can buy the car with them or without them.

As you pointed out yourself, you buy them if you want them—if you do not want them, you do not buy them.

We think, believe it or not, these options and accessories that we sell create a great number of jobs in this country and we are dedicated to the principle that what America makes makes America. We are bound and determined to make the finest product here a good value for our people.

The CHAIRMAN. You are making us buy a lot of options we really do not want. The brakes without power work just fine. You put cars in the showroom which all have power brakes and the pushbutton windows and all have air-conditioning and all have curved glass, high tail fins, and one thing or another. That is really not necessary.

Who was it who offered tail lights on the car which went off and on, zooming back and forth? There used to be only one stoplight on the back of an automobile.

Who produced those on the automobiles?

Mr. SMITH. Fred, I think he is talking about the sequential turn-lights that you had on your Thunderbird.

The CHAIRMAN. It looks like an expensive roadside advertising sign. All of that costs money. It seems to me that we do not need all of that.

This punitive tax does not appeal to me much. It seems to me that your Ford LTD is a good buy. It is a popular car with the public, and General Motors has a car comparable to that—which car is a similar model to the Ford LTD, in that price range?

Mr. SMITH. We think we bracketed it with a full line of cars. I would say probably the Chevrolet Caprice line on into some of our Pontiacs. It is a very, very competitive market out there, Senator.

The CHAIRMAN. Every one of those cars would pay the tax under the House bill, would they not?

Mr. SMITH. No, sir.

Mr. SECREST. They certainly would not.

The CHAIRMAN. Let us talk about the big Ford LTD, the one with the big trunk. Would it pay the guzzler tax or not, under the House bill?

Mr. SECREST. I think the short answer is that under the proposal made by the administration in April, almost all family-sized cars, like the Ford LTD and the Chevrolet Caprice would have been taxed in every year to some extent, because, by definition, they would be below the average of the fleet.

If the average of the fleet goes up to 27.5, those cars might be at 23 or 24, and they would have been taxed.

Under the bill passed by the House of Representatives, the tax begins at a point further down the scale, so there is a chance—a chance, certainly not a certainty—that some portion of the cars you are describing would not be taxed.

In our case, we forecast that we could pay up to $200 million a year in taxes under the House bill in some future year, but if we do an outstanding engineering job, we might be able to reduce that substantially.

The CHAIRMAN. I do not care to penalize the companies, but it seems to me that if I, as a consumer, would like to buy that automobile or a bigger one, I ought to have that privilege. I simply ought to pay something for it.

What I am concerned about in finding ourselves in the situation where pressure is exerted on your companies, as has been done, to make you produce more cars. Having done that, additional taxes are a drag on the market. Everybody may be trying to get a larger car. A dealer takes a customer out to the local tavern, entertains him at the country club and the customer tells him: "The next time you get an LTD, put it aside for me."

But nobody prefers a smaller car. If we do not tax larger cars, it appears to me that the Government has made the manufacturers produce small cars that they cannot sell, and to balance that, has put a tax on the larger cars.

I fully expect to buy one of the cars that bears the tax. The car I have now would bear the tax certainly, and I might buy one that pays the tax as well as one that does not pay the tax.

I think anybody with a two-car family would be wise to have one of the small ones because gas rationing might be required one of these days if the Arabs get their noses out of joint. In that situation, every family would do well to have one small car, and a very small one at that, in case of gas rationing.

On the other hand, why should we not impose a tax, boost the price, and make people pay more for a big automobile? It seems to me we ought to do something to stop the trend toward bigger cars and away from the smaller ones.

When there are a lot of small cars that cannot be sold and not a car for sale in the big car class, they are grabbed as fast as they come in.

Mr. SMITH. Let me say this, Senator, if you saw the chart over there, small cars are increasing. I think you may be an exception in that; as you can see, the small and midsized cars have increased their percentage of the market, and not only that but in addition to what you see there, the cars we are building, we are taking 700 pounds out of the full-size cars and a similar reduction on the midsize.

What I think we worry about is this: If you are the only person who is going to pay this tax, or one exception, I do not think that that would disrupt our industry. What we are trying to say is this.

There are already sufficient incentives for us to do this without this additional tax burden, and this additional tax burden could be very dangerous to our industry and to the country in that it could disrupt our marketplace.

As the ITC studies show, it could put people out of work. That is a thing we are trying to avoid. We are trying to keep a balanced growth.

We think energy conservation is fine, but we do not want to conserve ourselves into a recession. The automobile industry has been through a recession recently. We know what it is to have people out of work, and that is not a very good thing for us or for the country.

We think that there are sufficient incentives in there for us to do the job right now, and I think that the progress we have demonstrated in increasing fuel economy shows that we can do it, and it shows on a fleet average basis what we have been able to accomplish in solid energy savings.

To put something on top of that, that could potentially be a disruptive force and cause unemployment, to us does not make any sense.

The CHAIRMAN. I personally want to see you produce a lot of automobiles. If it takes some action by Congress to keep this tax from putting you out of business, I expect to vote for it. But on the other hand, I think that we do have a right to complain about the fact that the industry permitted the Europeans to get way ahead of them, and the Japanese also, with small automobiles. They went after the small car market in their first. They had a large market share before the domestic industry really went after that market the way we would like to see them do it.

I am not sure that we are going to be critical of the gas guzzler tax. If you are looking at consumer demand, we ought to put a tax on large automobiles so that consumers will not demand them so much, so the pressure to buy the big automobile would be offset by the higher price.

I think it would do a great job. It seems to me that we ought to be using small automobiles. I do not know how we can resist consumer pressure for big cars except by taxing them, making them cost more money.

Mr. SECREST. I guess, Senator Long, perhaps we should say if you are right and it proves very difficult for us to induce consumers to buy a high mix of our small cars of the future, which we believe and hope are going to be exciting and dramatic automobiles that people will want to buy, let us assume that they do accumulate and the demand is for only the largest of the cars. Under the law that was passed 2 years ago, and it has not yet gone into effect; it just starts this fall, we are required to take actions of our own to correct this problem you paint of the small cars piling up in inventory.

We have to be prepared. We do not need to have taxes and rebates in Washington to move. We will, because the law requires it, to adjust prices, our production schedules, our advertising strategies, our optional equipment or whatever, to make sure that, if we guess wrong, we quickly take the kinds of action needed to bring our total mix back to the level that is required to meet this, very, very difficult law requiring a doubling of the average fuel efficiency.

I think most companies, sometime during the next 8 or 10 years, will find that they misguessed the mix and they will have to do some dramatic things, short term things, involving price changes and production changes and equipment changes, but the law requires us to do it and gives us the flexibility to do as much of it as we need at the times when we need it.

The CHAIRMAN. If the tax in the House bill remains in the bill, how are you going to try to produce a Cadillac or a Lincoln that does not pay the guzzler tax? It seems to me that people would expect to be able to buy a big automobile and would expect to pay for a premium car that is expensive and uses more energy. They ought to pay the tax.

It costs a lot of money to drive around in a Cadillac or a Lincoln. They are great automobiles. I think the public ought to continue having the privilege of buying them. I think when they buy them, they ought to be prepared to pay a tax.

Mr. SMITH. Let me say this. I think there are other ways of doing that which are more effective. For example, for Cadillacs or Lincolns, what I would envision is something like putting a diesel engine in them that has a premium cost possibly, but at the same time we can do the job without the danger of disrupting the marketplace so much that unemployment results.

As I say, there are a lot of alternatives. We, for example, believe that a lot could be done to encourage the domestic exploration and production of oil to get more self-sufficiency. There are a lot of alternatives.

We think, for example, that a lot can be done on our highways to increase fuel economy. Right-turn on red has been a very good thing. We have just scratched the surface.

There are other things that can produce results without the big specter of unemployment hanging over our heads.

The CHAIRMAN. We are going to help you. Do not worry about that. Come see us.

As a matter of fact, I would be happy to help you to put a plant in Louisiana right now. We want to help to provide the jobs. We also want you to do your part, not come here and say, look, let the other guy do something about saving on energy.

We are glad to have your suggestions, but we want you to do your part, too.

Senator Hathaway?

Senator HATHAWAY. Thank you, Mr. Chairman.

You mentioned diesel engines. Wouldn't you be able with diesel engines, to make the gas guzzlers not gas guzzlers?

Mr. SMITH. We certainly hope so.

Senator HATHAWAY. How long will that take?

Mr. SMITH. We are coming out this fall with a brand new diesel engine developed specifically for our Oldsmobile passenger cars.

Also, we expect to put it into certain light trucks to see what the public acceptance of them will be. We have very great hopes for that. We think the diesel engine does hold out great promise for us. Its future has been slightly clouded by the emissions standards. We now have to see what our engineers can do to fit this program into it.

Certainly the diesel engine is only one example of a great development that we think can help in fuel conservation and still provide people with the type of transportation they need.

Senator HATHAWAY. Would that alone eliminate the gas guzzler tax on big cars?

Mr. SMITH. I do not think so by itself. I do not think we could get to an all-diesel fleet that rapidly. The diesel is, after all, a premium-price engine, because of the features it has, its high compression, and other things like that. Particularly in occupations, we think, where you do use your vehicle quite a bit. I am thinking again of possibly taxi fleets, small trucks, and vans are going to be a fine application for that, because they can absorb that and the fuel economy will be a good return for them.

Senator HATHAWAY. What other efficiencies are you trying to effect in the design and the types of material? I understand that normally, the heavier the car, the more gas it is going to use?

Mr. SMITH. Absolutely.

Senator HATHAWAY. You can probably maintain a large car by making it lighter. You mentioned you do not want to deprive the lower to middle income persons with a large family, to buy a car that would fit his family, although I have seen a couple of advertisements where a couple of football teams get into a Volkswagen, so I am not sure you are right.

Mr. SMITH. You are right when you say that, Senator. In our 1977 cars we took out 700 pounds on the average and in fact, we increased certain dimensional features of the car. We are doing that with our intermediate sized cars this year. We will be doing the same thing with other cars down the road.

That is, potentially the greatest opportunity for fuel savings, that we have.

Other things that we are looking at—aerodynamics—the possibilities are exciting to us. All of us know that cars have to become more efficient as they go and have less drag. I would say that is a new and exciting development to us. We are constantly refining our engines, drivelines, even small things that we find out we are able to do with tires all contribute—and of course, once we take one thing and improve it, we are able to spread that across our line to where it has a cumulative effect. That is why we feel confident that we can meet this fuel economy challenge and still do it with cars that people need.

Senator HATHAWAY. Assuming the gas-guzzler tax were going into effect, what would be a realistic time to postpone it, from your point of view, so you would have time to incorporate some of these efficiencies?

Mr. SMITH. I guess the postponing it—we are doing everything we can right now. Again, I know what Senator Long says about unemployment. We just have to let the market handle this for us and do this without disrupting it.

The potential unemployment is a problem that is of great concern to us. We think we can do this with just the incentive for us now. If you tell somebody if he does something wrong, you are going to shoot him, and on top of that, you are going to hang him as well—we do not need anything in addition to what is in the law right now. We have plenty of incentives to do our job.

What we are afraid of is by putting something on top of this, possibly disruptive, it may actually stop us from getting there and be antifuel savings for us.

Mr. TERRY. I would like to corroborate that statement. I am sorry I was late. I had plane trouble.

The point we are really making in our testimony and the basis of our objection to the so-called gas-guzzler tax is the fact that we are concerned it would prevent us from actually planning to build family-size cars in the 1980's, because now we are talking about putting on a gas-guzzler tax of $300, $500 or $700, which is a very high tax on cars that are getting 21, 22, 23 miles a gallon. Those are not gas guzzlers, by today's standards.

When you get up to 21, 22, 23 miles a gallon, that is an entirely different range of fuel economy from what anybody has ever been able to achieve in a family-sized car. Sure, we are going to make some improvements. We are going to make them a lot lighter. We are not going to build as much performance in them. We are going to do a lot of things that are going to help.

What we are concerned about is putting this gas-guzzler tax on top of the EPCA requirements that we already have, suddenly makes it almost impossible for us to come up with a product plan that would still allow us to keep the family-sized car in the picture, you see.

We believe that the heart of the market, really, in this country is still what we call the family-sized car and we believe that this is the kind of car that the people who can only afford one car really want and need because it takes care of all their needs.

By putting in the so-called gas-guzzler tax that will actually tax cars that make 22 and 23 miles per gallon in 1984 or 1985, we do not really think that we at Chrysler would want to plan that kind of a car for that time, because we are afraid that with the tax on it there will not be a demand for it.

The tax would actually keep us from planning such a car or such a line of cars, and we were just on our way, after going over hundreds of product plans for 1980 to 1985, how we were going to double the fuel economy in that short a time with new engines and transmissions and car bodies, how we are going to double the fuel economy and still make cars that people will buy, that they need and want. Get them that small, we know that is not the heart of the U.S. market, no matter how you look at it.

You say imports have made inroads; they have, but 85 percent of the market is still for the U.S. car and for the bigger car. When you throw in this monkey wrench with the gas-guzzler tax on top of what we are already trying to do, it limits our ability to plan a product line intelligently for that period.

Senator HATHAWAY. It would not inhibit you if it were postponed or phased in. As a practical matter, I think it is going to go through. I am just asking you if you could offer an amendment to make it effective a year later or phase it in over a period of 2 years, or what?

Mr. TERRY. Postponing, I still say is not the answer. We are doing everything we know how and we still have not quite gotten there, to figure out how we are going to make the average fuel economy requirements with the line of cars we can sell.

Mr. SECREST. I think, Senator Hathaway, if I may, the original administration proposal issued on April 21, would have applied the first so-called gas-guzzler taxes right now, in August or September of this year on the 1978 models, obviously too late for any manufacturer to take any kind of remedial technical action, and the action taken by the House has eliminated 1978. It has left the initial so-called gas-guzzler taxes in, in 1979 and 1980, at levels substantially lower than the administration version.

If I had to accept your rather pessimistic view, which may well be right, that action of some kind in this area may be inevitable, I think that, if things do not get any worse for the next 3 years than the level of the House, we do not have a major short-term problem, but beyond that, when we go to the 23.5 mpg tax situation, we face the kind of problem that my colleague from Chrysler is describing.

It is not at all clear that we can do both of these things, achieve an overall fleet average double what it was as recently as 1974 and at the same time, retain the flexibility to have, within that average, the kind of cars that will do the job that people seem to want done.

I guess we have the option, every producer has the option, of meeting the standards by going to a single line of cars, all Volkswagen Rabbits or all Club Wagons or whatever. Some producers here or abroad may have to take some option like that.

If it is costing us $8 billion to try to revamp our entire line to fit within these standards, $8 billion is a lot of money; not everybody has that. I am not sure we will have it.

There is the other option, but there is no doubt that if we do have to take an option of restricting the breadth of the line I think that we will sell fewer cars and employ fewer people. Some customers, I believe, will hold on to their old so-called gas guzzler rather than go all the way to the smallest possible car.

Senator HATHAWAY. Thank you. My time is up. I will come back to you later.

The CHAIRMAN. Senator Matsunaga?

Senator MATSUNAGA. Thank you, Mr. Chairman.

I welcome this opportunity to have the three leading car manufacturers of America before this committee, because I have always insisted that my own children—I have five of them—buy American. When one of my daughters recently graduated from high school and she wanted to buy a foreign car I said. "No, you shall not buy a foreign car. If you do Daddy will not pay for it. You will buy American." So she did buy an American car.

I will not say what make of car she bought, because we are not allowed commercials here, but that car was constantly in the garage, and my neighbor—the neighbor is a classmate of my daughter's—bought a foreign car and they were laughing at us because our American car was constantly in the garage for repairs. It was a gas guzzler too. But the neighbor's foreign car was running smoothly, giving maximum mileage.

Now there was a time when Americans led the field in technology. Whenever you bought American, you bought quality, but it seems the reverse is true now in the case of cars, especially among the compacts.

Why have we come to this situation, not only in relation to gas consumption, but in relation to maintenance, the durability of the car, and so on?

What has happened to the American car?

Mr. SMITH. Well, Senator, your experience, I think, might have been unique. We feel that there is no technology in the world on automobiles that anybody has better than the United States. I speak not only for General Motors, but for all our American companies. I think the finest cars in the world are made right here in America. We take great pride in our cars.

Anything with 15,000 parts in it can have some difficulties. We make provision for that. We stand behind our products. We warrant them to run well and we try and provide service through our dealer organizations.

I think that American cars do provide good fuel economy. Our Chevrolet Chevette, for example, in the EPA guide here is listed at 36 mpg in the composite fuel economy—that is the mixture of the city and highway driving.

We think we are going to have more fuel-efficient cars coming on the road. We are planning for it.

We recognize the challenge of the imports. We intend to meet them head-on in marketing and everything. We think we can build a better car than they can, head to head. We intend to meet that challenge in the market.

Senator MATSUNAGA. I am glad that it was a General Motors man who answered the question, because I have been a General Motors customer throughout the years. Now, you know that that car I was talking about was a General Motors product.

It is not only in the area of gas consumption, I think, which makes a consumer decide on what car to purchase, but the service as well, and the service on new cars has deteriorated to a miserable extent—I will cite you one example.

I have a Pontiac. You know that little decoration on the lock to the trunk?

Mr. SMITH. Yes.

Senator MATSUNAGA. It dropped off after 3 days of driving. [Laughter.] I do not know how. Do you know how long it took me to get one back on? Six months. Six months! Then I lost a hubcap. [Laughter.] Do you know how long it has taken to get it replaced? Six months, and I still do not have it.

These are the little irritants which make American consumers turn to foreign cars.

Mr. SMITH. Senator, I could not agree with you more. This is our challenge, to provide this service.

Mr. TERRY. I imagine you will get a hubcap.

I certainly do not agree at all. As a matter of fact, I think, if you take a realistic and objective survey of satisfied and dissatisfied owners with service and all of the rest of it, you will not find import cars ahead of U.S. cars. In fact, we have done that.

I am not trying to detract from what imported cars have done. Some of them are excellent products.

But when you talk about availability of parts in the field and about service and a lot of other things, I can find three or four import car owners that are just as dissatisfied with the kind of service that they have gotten as you can find domestic owners, at least in the same ratio.

Senator MATSUNAGA. I confine myself to American cars because I do not have any experience with foreign cars.

Mr. TERRY. Some people buy one foreign car and never buy another one, and they say they would not buy another one of those foreign cars. No matter what happens, I am going to buy a U.S. car.

Senator MATSUNAGA. You would not be a nice president of Chrysler Corp. if you did not, would you?

Mr. TERRY. The fact still remains, Senator, as I said, the imported cars are still getting about 15 percent, at one point almost 20 percent, now back again they are getting about 15 percent of the market. If you compare the performance of our U.S. products, there are no trade barriers against import cars coming in, as you know. They are one of the few products—it is about the only country in the world where I can think of where cars are brought in on a completely trade-barrier-free basis, yet we still maintain, by far, the majority of the market in this country.

I get tired of being put on the defensive about import cars versus U.S. cars. We do not deserve to be on the defensive. I do not think we are on the defensive. So when we come up to talk to people who tell us about an individual experience they have had, we know there are those. There are those with foreign cars, also. I do not think we have to take a back seat in the auto industry to any other industry anywhere.

Senator MATSUNAGA. I do not think that you need to take a back seat anywhere, but I think you can improve a lot.

Mr. TERRY. We are going to improve.

Senator MATSUNAGA. Believe you me, the Vega, which I bought for my daughter [laughter] I'm sorry I named it, but—do you know what I was told by the service people? "You just got a lemon," they said, "we cannot help you; you just got a lemon." There should not be any lemons.

Mr. SMITH. There are not. That was a poor excuse somebody gave you. I would like, if I could sometime, to discuss it with you because, I assure you, we do not build lemons, and neither does Ford or Chrysler. The cars that come off that line are put through thousands and thousands of inspections to make sure that they will function properly. Sometimes in dealer service or transportation things do happen, but they can be fixed and should be fixed.

Senator MATSUNAGA. As one Member of the Congress, let me assure you that I am on your side, and on the side of American manufacturers of cars, because when I told my daughter no foreign cars and she said, "Not even a Toyota?" I said, "Not even a Toyota."

Mr. SMITH. Good for you, Senator.

Senator MATSUNAGA. Now, Mr. Secrest, you say on page 4 of your testimony that you cannot predict the mileage on a car prior to its being run off the factory lines.

Do you mean that, with all your technology and your expertise and your experience, you cannot predict what the mileage, what the minimum mileage would be prior to getting the car off the factory line?

Mr. SECREST. Let me try to clarify that, Senator Matsunaga. It is not as dismal, perhaps, as it sounds.

We have, and we must have under the EPCA law of 1975, very detailed engineering projections, year by year, model by model, not only for the car lines themselves but for all the permutations of car lines with different engines, different transmissions, different axles. There is a whole computer deck of engineering projections that are revised at least monthly during the whole preproduction period.

However, when you come right down to the final test, which is administered, as you know, by EPA and not by the companies, those cars are tested for official Government fuel economy purposes governed by the 1975 law, at the time that they go into production. They do not test prototypes. We test prototypes. We try to learn enough so that we can anticipate, with reasonable confidence, of course, where we will come out.

The EPA and DOT people themselves point out that there is a plus or minus 10 percent variability on the test results that you may get from one lab to another on an identical product.

This means that you must retain an element of conservatism or safety in your engineering planning. You cannot forecast down to the exact hundredth of a mile per gallon of what the final test will show. Under the fleet average concept in the 1975 law, we can live with this kind of a risk, because statistics show us, some cars will fall below our plans and others will come out above the plans; we will do better.

Under the proposal passed last week by the Senate Energy Committee the units that fall below would be prohibited altogether, or fined $10,000 a copy which is the same thing. We think that is a very severe risk, because you are unable to predict, on every one of the literally hundreds of variations, the exact measurement of what will finally come out of the EPA test.

Senator MATSUNAGA. You do put every car under tests before you release it?

Mr. SECREST. Yes, sir, not once but many times, through the development program so we can make engineering changes if we find that some idea does not appear to be working and we need to do something else.

Senator MATSUNAGA. Mr. Chairman, if I may be permitted to ask one more question, although my time is up: We are concerned about conservation of fuel, of course, and perhaps going to diesel is one thing, but what about going to electric cars?

When will electric cars be the car on the road in America?

Mr. TERRY I would like to take a crack at answering that, if I may. We have done a lot of work on electric cars. The principal problem with electric cars is the weight of stored electrical energy. You have to carry your energy around with you in an automobile, and in the case of electric cars, you have to carry the electrical energy in batteries.

The quickest way I know of explaining how heavy electrical energy is, is to point out that one-half gallon of gasoline takes 1,000 pounds of lead acid batteries to give you the same amount of energy.

This means when you start putting batteries in any kind of a car to give you the electricity to drive it that you have a big penalty right off the bat in weight, and this limits your range and your performance and your maximum speed.

There are going to be battery breakthroughs. Lead acid batteries are the best we have today.

But even the breakthroughs that you are talking about that are on the books and possibly are maybe half the weight or a third the weight or a quarter of the weight of that acid battery and that still makes them very, very heavy, for carrying that energy around with you.

I still believe, personally, that there is a future for electric cars in the 1980's, for limited purposes, let us say commuter-type distances, twenty miles at a time. That still leaves some room for error, because you do not want to run out of electrical energy any more than you want to run out of gas—as limited purpose vehicles developed in the 1980's, and I think they will, with these fuel economy reforms and so on, there are going to be some electric cars.

They are going to be useful for shortrun kind of situations where not too much performance is required.

Senator MATSUNAGA. I was told by a representative of the Electric Car Co., I believe from Colorado—are you familiar with the company which puts out the so-called electric car? I think the name is Electric Car.

Mr. TERRY. I do not believe so.

Senator MATSUNAGA. The representative of that company—I know it is based in Colorado—came and showed me slides and showed me their electric car. Heavens, it looked like a Pinto almost. And he said they have the technology today of giving it a range of 100 miles or more.

And he envisioned each service station having replaceable batteries. That means that you pull into, not a gas station but a battery station; pull out the used set of batteries from your car, replace them with a charged set of batteries, in a matter of a few minutes, and you are off on your way for another 100 miles.

Mr. TERRY. That is perfectly feasible. This business about the batteries, it is a large capital expense, taking somebody else's batteries and putting them in your car and leaving yours behind, poses certain problems. I think we are going to find that the uses for electric cars will be mainly by individual consumers who have only short distance requirements and can plug in their own batteries in their own household outlet to begin with, plus some commercial users who will be able to control their own batteries.

Senator MATSUNAGA. I'm sure it can be done, As a matter of fact, we do have electric cars in certain agencies in the Federal government right now. The Post Office Department, or the Postal System, for example, use some electric cars.

Mr. TERRY. We have inquired into that. We are trying to follow the actual progress and the service that people are getting out of their electric vehicles, as closely as we know now. If the Senator will investigate himself, he will find there are still a great many shortcomings in these electrical vehicles being used.

I think a lot of these will be worked out; I think we are going to have electrical vehicles in the 1980's. It is going to be limited applications, and I do not see them as taking over the market or ever providing the same kind of general service that you get with our gasoline-powered automobiles.

Senator MATSUNAGA. Would you say the early 1980's or late 1980's?

Mr. TERRY. There will be some in the late 1980's. There are some now, as you pointed out. I think those are going to continue to grow at a modest rate.

Senator MATSUNAGA. Thank you very much.

The CHAIRMAN. Senator Packwood?

Senator PACKWOOD. I have no questions.

The CHAIRMAN. I just want to ask about one or two matters. What is the environmental price that we are paying right now in energy? For example, some of my environmentalist friends would like me to believe that automobiles are getting more mileage because we have environmental protection laws which control exhaust pipe emissions.

What do you estimate is the environmental price we are paying in terms of mileage on automobiles that are coming off the line now? How much more mileage would they be getting if you did not have to comply with any environmental requirements on tailpipe emissions other than just the muffler to cut down the noise?

Mr. SMITH. There are a lot of figures on it. What our goal is to reduce that with new technology, but I guess the best thing with field experience, you can see right now between the 49 States and California, the difference there, I believe, is about a 10-percent penalty in fuel economy.

It is demonstrated in the fleets and in these EPA mileage guides. EPA puts out a book for the 49 States. They put one out for California. I think the comparable cars in there have an average 10-percent penalty, and probably that is not too far off from the real world.

Our goal, of course, and we have to do this, is to find ways to reduce that penalty down to zero. As a nation, we cannot afford those penalties.

All of us have our scientists working hard on new systems, particularly now. We will have more stringent emission requirements to meet. We will just have to keep our scientists dedicated to coming up with new ways of doing this, so that we do not have a fuel loss. All of us are dedicated.

Mr. TERRY. Originally, when we first began to reduce emissions in automobiles, we were able to make very substantial reductions in carbon monoxide and unburned hydrocarbons just by burning leaner and doing a better job of combustion in the cylinder. This actually made the cars more efficient, not less efficient, so we were able to actually improve fuel economy at the early stages. We might have been able to go quite a bit further, given enough time, by just improving the combustion process more and more, getting better distribution and running leaner and leaner and this will reduce emissions.

The problem is that the emission requirements have gotten tighter faster than our ability to keep on trying to do a better job in the cylinder, trying to do a better combustion job.

As a result of the requirements going faster than we are able to move without technology, we had to start adding things on that would reduce emissions and we did some things that we did not want to do that were actually inefficient, to reduce oxides of nitrogen, particularly, because oxides of nitrogen—there are three different kinds of pollutants, designated pollutants, from automobiles: unburned hydrocarbons and carbon dioxide. The third, the oxides of nitrogen it is the other way around. It is simply a combination of the oxygen and hydrogen in the air, the two principal ingredients in air.

These two ingredients, these two gases combine any time the air gets heated any higher than 350° Fahrenheit and they combine at a very rapid rate, an accelerated rate, as the temperature increases to about 3000°. So in order to reduce oxide of nitrogen formation, we have to reduce the temperature of combustion in the cylinder and since a heat engine produces energy from high temperature, that means we have to do something that would actually make the cylinder run cooler.

It means it is going to run, generally speaking, less efficiently. It is oxides of nitrogen control that has been the principal problem as far as losing efficiency, losing fuel efficiency, in our engines.

The CHAIRMAN. What is it that makes your eyes tend to burn? Is that oxides of nitrogen, or other pollutants?

Mr. TERRY. That is called photochemical smog oxidant. It is caused by a combination of unburned hydrocarbons and oxides of nitrogen in the air together in a temperature inversion under the action of sunlight.

I might point out, while we are on that subject, there was photochemical smog in the air before there ever were any automobiles, and EPA's own projections show that in many areas, including Washington, D.C. here, that if you completely eliminated all automobile exhaust you would still exceed the ambient air quality standards for oxidants in the National Capital area.

That is also true in Los Angeles.

When we start to blame everything on pollution from automobiles, whenever there is a temperature inversion, that is due to automobile exhaust, that is not correct. That is greatly overplayed in the situation.

If there were no automobile pollution at all, they would still exceed national standards in a number of areas.

Mr. SECREST. Under the confluence of two laws both on the books, the amendments to the Clean Air Act that were signed this past week and the EPCA law of 1975, we will all have to obtain these future fuel efficiency standards roughly double the 1974 levels while at the same time finding some way to overcome the 10 percent or more present fuel efficiency loss associated with meeting the tighter emission standards.

It is really more than doubling; we have to double the fuel efficiency, and at the same time be smart enough over the time period we are given to find ways to offset the penalty associated with moving toward the ultimate emissions level.

I think we can do it. It is another major chunk of cost and engineering requirements.

The CHAIRMAN. I think one other thing ought to be said about the matter of quality. Some foreign automobiles are very good cars with very good workmanship, but if you look at the price you are paying for them—for example, a Mercedes is a very fine automobile and it has great workmanship—I still would rather have what you can offer from any one of your companies.

A relative of mine bought a Mercedes. To me, that was ridiculous. If you look at what you can get in terms of a competitive American automobile—it is true you have a fine product in a Mercedes—dollar for dollar, I think each one of you has a better product to offer for the price. I would rather have an American automobile than the Mercedes. Everybody I know who has a Mercedes brags about it, but they are also often in the shop. Do Mercedes customers people have a preguaranteed automobile shop?

Mr. SMITH. They may have a warranty, as many of us warranty our products. I am very happy to see that we have to compete with the Mercedes in the entire world market. We believe our U.S. cars do provide the value for their dollar.

The CHAIRMAN. There is only one thing I would like to see from all three companies, and that is to put pressure on the dealers to take care of the traveling public on an emergency basis. My impression is that the average dealer is going to favor his regular customers. If your car shows up limping and it needs repairs, it is difficult to get the dealer to put your automobile on the line and get it repaired ahead of a regular customer who has been scheduled to come in that morning to have his automobile repaired.

I have run across that problem and I think other's have, and I would hope that the companies would put the pressure on their dealers to give a priority to some fellow who comes off the highway and his automobile needs emergency repairs.

Is there any way you could try to do that?

Mr. SMITH. Within the limits of the fact that, of course, these dealers are independent businessmen. We try, I would say, to provide the proper incentives to do that. All of us, I am sure, that problem of service in the field and are trying a lot.

General Motors has recently appointed a vice president in charge of consumer relations just to take on this entire service problem out in the field, to help our people and to help get better service from our dealers to our customers, because as you say, Senator, it is a large problem. We recognize it.

Cars are more complex today. They have a lot more equipment on them than they ever had before. The emission controls came into the picture; they are going to have a lot more in the future, and that is a great concern to us, to keep our automobile providing the service that the customer pays for.

The CHAIRMAN. I wish that you would do it rather than complain about the Government interfering with your business. If your companies do not do that, if you have a continual repetition of the kind of complaint I am familiar with, where someone comes in with his wife or his wife and children off the highway with the automobile needing some sort of emergency repair and being told at 11 o'clock in the morning by a dealer, "Sorry, we cannot put you on the line until 4 or 5 o'clock this afternoon to even see what is wrong with the automobile."

I wish you would encourage people to report that and find some way to tell those dealers that is not acceptable service for your company.

Mr. SMITH. I would say that some of us have regional offices and zone offices in many cities around the country that are there just to help in that particular situation and I would encourage you, if you know anybody who has a service problem, to get hold of the General Motors representative in that area for help, and I am sure he could help.

Mr. SECREST. We have also made it very clear under our warranty program that Ford will pay for emergency repairs at any Ford dealership in the country and not just at the selling dealer, so we have tried to eliminate any financial basis for a slowdown.

The CHAIRMAN. I think today some dealers would realize the problem and help the traveling public, the fellow who has an emergency immediately. Others take the attitude that that fellow is not going to be buying a car from them. He is some stranger from out of town; the heck with him, he can wait until the dealer has gotten through with all of his regular customers. Then he will check and see what the emergency is.

I would hope that the companies would try to do something about that. I think it would be good consumer relations. If you do not, one of these days you will be seeing legislation which will do it for you. Thank you very much.

Senator Hathaway?

Senator HATHAWAY. Mr. Chairman, a couple of more questions.

Could you supply for the record how much money you are spending for research in the area like diesel, lowering the weight, and so forth?

Mr. SMITH. We will be glad to.

[The following was subsequently supplied for the record:]

GENERAL MOTORS CORP.,
Detroit, Mich., August 23, 1977.

Hon. WILLIAM D. HATHAWAY,
U.S. Senate,
Washington, D.C.

DEAR SENATOR HATHAWAY: During my appearance before the Senate Finance Committee on August 10, you requested for the record information concerning GM expenditures on fuel economy. Specifically, you asked:

"Could you supply for the record how much money you are spending for research in the area like diesel, lowering the weight, and so forth?"

Following is a response to that question:

Expenditures in the U.S. related to fuel economy for calendar years 1975 and 1976 were $950 million and $1.3 billion respectively. These expenditures include research and engineering; reliablity, inspection and testing; capital facilities, special tools and rearrangement costs.

Included in the above, research and engineering costs related to fuel economy were $227 million in 1975 and $330 million in 1976 and include programs for vehicle weight reduction, diesel engines for passenger cars, aerodynamics, alternate power sources, and engines.

You may also be interested in the enclosed paper which discusses the much broader issue of the cost to General Motors of meeting government requirements. Since we consider fuel economy to be a marketable product attribute, none of the expenditures listed above concerning fuel economy are included in the cost of government regulation.

In order to comply with your request that this information be made a part of the hearing record, a copy of this letter is also being given to the staff of the Senate Finance Committee.

If I can be of further assistance to you, please let me know.

Sincerely,

ROGER B. SMITH.

IMPACT OF GOVERNMENT REGULATIONS ON GENERAL MOTORS

General Motors spent more than $3¼ billion in complying, and preparing to comply, with regulations imposed by all levels of government in the three years 1974–1976. That amount does not include the cost of equipment added to GM products to meet government standards, nor any taxes or workers' compensation claims paid. Neither does the $3¼ billion reflect the cost of lost opportunities, misplaced priorities and misused resources.

In 1976 alone, government regulation cost GM more than $1 billion, and required the equivalent effort of 22,900 full-time GM employes.

Total expenditures, by major category, for the three-year period were estimated to be:

	[In millions of dollars]
Regulation of Motor Vehicles	1,986
Regulation of Plant Facilities	502
Occupational Safety and Health	216
Government Reports and Administrative Costs Related to Regulation	589
Total	3,293

During the same three years the equivalent number of full-time employes required to comply with government regulations ranged from 22,800 to 25,300. Attachments A and B show the impact on costs and employment in detail.

Significantly, the nearly $2 billion spent on the regulation of vehicles does not include expenditures to improve the fuel economy of GM cars. In our view, such costs are competitive expenditures at this time. General Motors undertook the redesign of its vehicles for this purpose well before the government mandated fuel economy standards—an undertaking in response to consumer demands rather than government requirements.

In arriving at the cost and employment data, no attempt was made to differentiate between what might be considered necessary and unnecessary government regulation. While we believe much is unwarranted and should be eliminated, any attempt to separate such regulation would require subjective judgment. Our purpose was to be as objective as possible in arriving at the total cost of regulation.

SCHEDULE A

IMPACT OF GOVERNMENT REGULATIONS ON GENERAL MOTORS EXPENDITURES

[In millions of dollars]

	Calendar year— 1974	1975	1976	3-y tota
Regulation of vehicles:[1]				
Auto safety	414	347	354	1,115
Auto emission control	454	184	188	826
Vehicle noise control	16	15	14	45
Total	884	546	556	1,986
Regulation of plant facilities:				
Plant pollution control:				
Air	77	57	58	192
Water	56	54	56	166
Solid waste control	48	39	57	144
Total	181	150	171	502
Occupational safety and health	79	62	75	216
Government reports and administrative costs related to regulation:				
Business statistics	3	3	3	9
Energy management	21	23	25	69
Environmental activities	43	41	40	124
Industrial relations	44	48	61	153
Legal activities	26	25	34	85
Marketing functions	3	4	6	13
Taxes	12	12	13	37
Other	38	29	32	99
Total	190	185	214	589
Grand total	1,334	943	1,016	3,293

[1] Includes research and engineering, reliability, inspection, testing, facilities, tools and rearrangement costs. Does not include the direct cost associated with the product (except direct inspection).

SCHEDULE B
EMPLOYMENT[1]

	Calendar year— 1974	1975	1976
Regulation of vehicles:			
Auto safety	12,300	10,400	10,500
Auto emission control	4,800	4,400	3,900
Vehicle noise control	400	300	300
Total	17,500	14,700	14,700
Regulation of plant facilities:			
Plant pollution control:			
Air	800	800	800
Water	500	500	500
Solid waste control	500	500	600
Total	1,800	1,800	1,900
Occupational safety and health	1,100	1,100	1,100
Government reports and administrative costs related to regulation:			
Business statistics	100	100	100
Energy management	200	100	200
Environmental activities	1,000	1,000	1,000
Industrial relations	1,400	1,500	1,700
Legal activities	800	700	900
Marketing functions	100	100	100
Taxes	400	400	400
Other	900	800	800
Total	4,900	4,700	5,200
Grand total	25,300	22,300	22,900

[1] These estimates of employment including technical, clerical and other support personnel, were based on total hours worked as a result of regulations. Those hours were then converted to the equivalent number of employes working a calendar year.

Senator HATHAWAY. I take it your unemployment which you are talking about, is that people will shift to smaller cars and the foreign market will take up most of those. Is that the problem? You cannot compete with the foreign market on the smaller cars?

Mr. SMITH. It is not that. The ITC study that has been supplied to your committee discussed that unemployment problem.

Our automobile business is a very sensitive one, both to cyclical, seasonal, and other trends. We are not able to accommodate to shifts as fast as we would like to in some areas, particularly when the market gets disrupted by outside influences.

In other words, while overall you might say that we can do this thing in some particular plant, in some little town where we have been making, let us say, a V-8 engine that is now going to have to be changed over to a diesel faster than we had planned to do it on a gradual basis, you may find that you have a shutdown at that plant. That is going to put economic hardship in that town and those people, and we think that it is unnecessary. We can do this on a programed, reasonable basis, and avoid that kind of sporadic unemployment.

Over and above that, is the problem of the tax or rebate scheme that would favor imports. Obviously, anything that favors them is going to take jobs. I think the ITC estimate that we saw was something on the order of 90,000 jobs that could be lost in 1985.

Mr. TERRY. I would like to have a crack at explaining another aspect of this, please.

When we are asked to downsize our cars and make them twice as fuel-efficient as they are now in a period of 10 years, that is going to require lots of investment. We are going to have to redesign, redo every single car that we build, and the resulting cars will be different. They will be smaller and lighter in general.

We hope to keep the big family-sized car in the picture, but all of the cars will be markedly different. We know from experience that some of our customers will not like these smaller, lighter cars as much as they like the ones that we have got, so we are trying very hard to come up with a product line that will still keep a relatively constant market so that we do not go from a 10 million car year down to a 7 million car year, because that is a disaster from an employment standpoint.

We are trying to maintain lines of products during these 10 years that will still continue to give the average result, average number of new car buyers coming back to the marketplace every year. Which you can see, if we are forced to do this too fast, customers are going to rebel. They are going to come to the showroom and say, well, I do not like the cars this year as much as the one I have got. I will keep the one I have got.

A car is a deferable purchase for quite a period, so you could have a big slump in the overall market for cars if the trend is pushed too fast. Obviously, we are trying to avoid that. All of the companies are. We think we have product plans now, after looking at it for about 2 years, we think we have a product plan that will keep buyers coming in to buy our new products.

But now, when we put on top of that gas guzzler taxes or even ban cars completely if you do not meet certain mileage requirements and so on, there is another monkey wrench in our plans. We do not know whether we have a plan we can keep on getting buyers to come in and buy cars or not. And, of course, throughout the whole thing, it is true that since we are being forced, let's say, by the fuel economy standards to come up with much smaller, lighter cars, we are actually being forced to go into the import car area, and we are going to be competing on their home ground, to some extent.

They have already established a reputation, they have already tooled their small engines, small transmissions. They are already paid for, and so on. We are going to their home ground. We have to invade their market and that is going to be more difficult than if we were just staying in the market we had.

So there are some very substantial risks in just meeting these average fuel economy requirements which we are pledged to do.

What we hope we can do is avoid having these other things thrown in on top of the gas guzzler taxes and so on. That would make it even more difficult.

Senator HATHAWAY. You have had a considerable period of time to plan for the small, foreign car.

Mr. TERRY. Up until this point they have not been a sufficiently large part of the market to warrant our spending the tooling money that it would take to get into that business.

Senator HATHAWAY. The trend has not been increasing all the time?

Mr. TERRY. We have been getting smaller all the time. As a matter of fact, we at Chrysler just decided to go into the subcompact market before these laws were passed. We had decided to go into that market, but for many years, when import cars were being brought in with the tooling that they had in their own countries, the base for their base volume, they can send in 10,000 or 20,000 or 50,000 cars into this country very nicely because their tooling is already paid for, but it would not pay us for that kind of a volume to tool up these subcompact cars.

It has only been in recent years that the demand has gotten to a point where it does pay us to get into this market.

Senator HATHAWAY. Thank you.

Thank you, Mr. Chairman.

The CHAIRMAN. Senator Matsunaga?

Senator MATSUNAGA. Thank you, Mr. Chairman.

I want to follow up on the questions raised by the chairman relative to the use of the catalytic converter. Have you been successful in eliminating that sewage smell that comes out of that catalytic converter?

Mr. SMITH. We think that, properly tuned, odor should be at a minimum. There is always an atmospheric thing, certain driving conditions, that can occur momentarily. It should not persist as an ongoing thing.

It is hydrogen sulfide. I assume that is what you are referring to. It is sometimes a byproduct, and, under certain conditions of idle. That is one of our challenges, to get that out of our cars.

I would say that the catalytic converter, on balance, has certainly been a great boon to the automobile industry. It did allow us to achieve significant emission controls while at the same time allowing us to retune our engines for more fuel efficiency.

On balance, I think it has proved its worth.

Senator MATSUNAGA. Coming back to the electric car, I feel that American auto manufacturers should be the pioneers in this respect, not wait until the foreign manufacturers flood the American market. Maybe you could even start out with a car called "The Commuter," just for ranges up to 50 miles, just to go to and from work.

I think that in so doing, you could add to fuel savings and to the clean air that electric cars would also promote. I honestly feel that you should even have a crash program in this regard and maybe then as American auto manufacturers you will regain the position and the prestige that you once had.

Mr. SMITH. Senator, I can assure you that there is an electric car in the future at General Motors. We have an active program going on right now.

Mr. SECREST. We are working on an electric car, on a hybrid car—another possibility—which would combine a small gasoline engine with a battery system so you could switch back and forth and use the battery in the city and the engine on the highway.

This is an expensive proposition to design, but it might be a way to eventually increase the flexibility, the utility of the electric car concept.

I agree with Mr. Terry that there are some fundamental problems of battery design that we really have to solve before we can have anything more than a very narrow slice of the market in electric cars.

Now, I think there's also a question of whether the available amount of electric energy with all of its rising costs, including pollution control at the powerplants, may not be a limiting factor in the growth of electric cars. Our research people are really more interested for the longer term in the development of alternate liquid fuels not derived fully or completely from conventional oil—fuels such as methyl alcohol, ethyl alcohol, oil from unconventional sources such as shale and tar sands and things of that kind.

We think there is an excellent chance that by the late 1980's or 1990's that there will be significant experimentation with changing the liquid fuel base of the motor vehicle fleet so we do not have to rely entirely on conventional fossil petroleum to power the car.

Mr. TERRY. That is a very good point. If I may proceed just one more step, the electric generating powerplants use coal and oil and so on to produce electricity for the most part and we are really not saving any energy overall when we go to electric cars, as a rule, because of the inefficiencies involved in generating the electricity from the fossil fuel and then getting the electricity to the place where the outlet is, there are losses there. By the time you put it into the battery and then get it into the motor to drive the car, the overall efficiency from that point of view of the amount of fossil fuel used basically in the first place does not favor the electric car.

There have been several studies on that, which I will be glad to send you a copy of if you like.

However, if we say, OK, electricity is now available, because now we have nuclear fusion, fission or what have you, and we are generating electricity and that is no problem, it might actually be better from a standpoint of transportation vehicles if we used the electricity to break water, let us say into hydrogen and oxygen, and we use hydrogen to power our vehicles.

There are some problems in development along those lines. Storing the hydrogen in metal hydrides, it does not take the volume and the weight of electricity if you store electricity in battery form.

So there are many ways that we can use the electricity; by using the ordinary battery may not be the best one. We are experimenting and working on all kinds of ways for doing this.

Senator MATSUNAGA. Good. I would certainly like to see American industry make a pioneering effort in this regard.

Mr. Chairman, you told a story yesterday; I think it is my turn to tell a story about this Japanese gardener who came to America. Before long, he became a landscape architect and he became an American citizen. He was so proud of being an American citizen, he insisted on buying American cars. But as age crept up on him, he had eye trouble; so he went to see his eye doctor and the eye doctor looked at him and examined him and said, oh, Mr. Tanaka, you have cataracts.

Whereupon, Mr. Tanaka said, oh, no, doctor. Me got one Lincoln Continental. [Laughter.]

The CHAIRMAN. Thank you very much, gentlemen.

[The following was subsequently supplied for the record:]

GENERAL MOTORS COMMENTS ON ENERGY TAX ACT PROVISIONS AFFECTING MANUFACTURING ACTIVITIES

As passed by the House of Representatives, the Energy Tax Act of 1977 contains a number of non-transportation tax provisions which affect General Motors as an industrial corporation. The following are GM's views on the major non-transportation tax provisions.

CRUDE OIL AND NATURAL GAS LIQUIDS EQUALIZATION TAXES AND REBATES

As passed by the House of Representaives, the Energy Tax Act of 1977 would impose excise taxes on price controlled, domestically produced crude oil. The effect of excise taxes would be to raise the price of domestic oil to the world price of oil in 1980. Exemptions would be provided for heating oil used in residences, churches, schools and hospitals. The net receipts from the equalization taxes would be returned to individuals through tax credits or special payments.

The House bill would also impose taxes on sales of natural gas liquids to businesses. The taxes would rise in three stages to equal the difference between the controlled price of natural gas liquids and the wholesale price for No. 2 distillates in the region, adjusted for differences in Btu content. Exemptions would be provided for residences, farms, schools, churches and hospitals.

General Motors supports the concept that domestic oil should be priced at the world level. We also believe that the price of natural gas should rise to its market clearing level. Deregulation of new oil and natural gas would result in the price of these commodities rising to the level of their market value and thereby providing incentives for both conservation of existing supplies and development of new supplies.

The proposed crude oil and natural gas equalization taxes may provide incentives for conservation, but fail to provide incentives for development of new supplies.

The Congress should reject the proposed oil and gas equalization taxes in favor of dereguluation or, at a minimum, amend the House bill to provide incentives for exploration and development of additional supplies of oil and natural gas.

TAX ON BUSINESS USE OF OIL AND GAS AND CREDITS

The House bill would impose taxes in three tiers on the use of oil and natural gas as fuel by businesses. The highest taxes would be imposed on Tier 2 uses, generally in boilers or gas or oil-fired turbines or other combustor engines which have the potential for coal utilization. The lowest taxes would be imposed on Tier 1 uses, generally process uses for which conversion is not practicable, but which may have potential for conservation. The taxes on Tier 3 uses, generally for generation of electricity, would be delayed several years and then set at levels between those of Tiers 1 and 2. Feedstock uses would be exempt from the user taxes and process uses would be eligible for exemption on case by case determinations.

The effect of the user taxes on top of the equalization taxes would be to raise the price of energy to industrial users above the world price. The bill provides a credit for investments in qualifying alternative energy property which may be used to offset, on a dollar by dollar basis, the users' oil and gas consumption tax liability. As an alternative to the above credit, business users would be allowed a 10% energy tax credit (in addition to the investment credit provided under present law) for investments in qualifying property intended to reduce the use of oil, natural gas or other energy forms.

The industrial use taxes on oil and natural gas, like the crude oil equalization tax, will result in higher energy prices without any incentive for additional energy supply. In addition, the user taxes on oil and gas could penalize industry by requiring domestic manufacturers to pay for oil and natural gas at levels above world prices.

As passed by the House of Representatives, the industrial user tax provisions of the *Energy Tax Act* are significantly improved over the proposals submitted by the Administration. The latter proposals would have applied taxes on all industrial uses of oil and natural gas, regardless of the potential for conservation or conversion to coal or other abuandant energy sources. Clearly, taxes should not be applicable to those industrial uses for which there is little or no conversion or conservation potential. Unfortunately, the House bill provides for cumbersome, case by case determinations on exemptions of the process uses farm taxation.

The *Energy Tax Act* should be amended to delete the tax on business use of oil and gas, or, at a minimum, the tax should apply only to specified uses (such as gas or oil used in boilers, turbines or other combustor engines) which have significant conservation potential.

If the industrial user taxes are not eliminated, the Energy Tax Act should provide for the dollar for dollar tax credit against the user taxes and, as an alternative, the business energy tax credits discussed above. Unfortunately, the House bill apparently allows tax credits for only some of the property required for the use of alternative energy sources. The legislation should be amended to cover all of the property required for use of alternative energy

The CHAIRMAN. We will call Mr. Robert McElwaine, executive vice president, American Imported Dealers Association.

We are limiting all witnesses to 10 minutes for their presentation in brief, and then to respond to questions.

STATEMENT OF ROBERT M. McELWAINE, EXECUTIVE VICE PRESIDENT, AMERICAN IMPORTED AUTOMOBILE DEALERS ASSOCIATION, ACCOMPANIED BY BART S. FISHER, ESQ., PATTON, BOGGS & BLOW, WASHINGTON, D.C.

Mr. McELWAINE. Thank you.

Mr. Chairman, distinguished members of this committee. My name is Robert McElwaine and I am executive vice president of the American Imported Automobile Dealers Association, representing the 4,800 American small businessmen who sell and service imported automobiles and their 127,000 employees.

I am accompanied today by Mr. Bart Fisher of the law firm of Patton, Boggs & Blow, as counsel.

The imported automobile dealers of this country, like all of our citizens, have a vested interest in energy conservation and subscribe wholeheartedly to the objective of the President's National Energy Act: namely to reduce the imbalance in our trade payments brought about by inflated prices of foreign oil.

Such an imbalance creates, as you are obviously aware, special pressures upon our industry over and above our considerations of the impact on the national economy. The imported car dealers feel they make a substantial contribution to energy conservation by offering the public a product that, in general, is the most fuel efficient available to the automobile buyer and thereby providing the spur of competition to domestic manufacturers to improve the fuel efficiency of their own product.

We are troubled by many aspects of the President's, which we feel, in general, overlooks legislation already enacted by the Congress and offers additional proposals in our particular field that, at best, are cosmetic in their effect, and at worst, counterproductive.

Our principal points can be condensed to five, and I will go through them briefly and then be open to receive questions.

One, as was stated so well by the domestic manufacturers, the Energy Policy and Conservation Act of 1975 has had, and will have, an explosive impact on the automobile industry. The fleet average fuel economy standards mandated by that bill are not only sufficient to achieve satisfactorily fuel-efficient automobiles by 1985, but they are more effective in this sense than any of the measures contained in the new energy act.

The auto efficiency standard and penalty operates, in many respects, as an indirect auto inefficiency tax and rebate for any auto manufacturers whose fleet average gas mileage is at, or below, the standard.

Although the penalty under EPCA is $50 for each car in the fleet for every mile by which the fleet average falls below the standard, the implicit penalty on an inefficient car is much more than $50. First, since the penalty is nondeductible for tax purposes, it is the equivalent of increasing the deductible costs by almost $100 per car. Secondly, when the penalty is allocated only to the inefficient car—as opposed to the entire fleet—it far exceeds the post-income tax cost of $100 per car per mile below the standard.

Consequently, the contribution of a very inefficient car not meeting the fleet standard and causing the $50 per car penalty to be imposed on the entire fleet is substantially greater than the contribution of one slightly below the standard.

In our written testimony on page 7 you will find a table that shows the actual size of the individual penalty per car under the current law and, as you can see there, the 1980 penalty on a car getting only 10 miles per gallon is $2,000. In 1985, that penalty is $4,183.

As the table indicates, the proposed tax and rebates would simply add on lesser layers of levies and rebates to current implicit taxes and rebates in effect under the EPCA.

The American Imported Dealers Association believe that this is an unnecessary exercise, and should not be undertaken, especially in light of the progress that has been made already toward meeting the standards established by the EPCA.

Our second point is that the proposed tax on the fuel inefficient automobiles will have an impact best described as marginal. Actual savings in gasoline consumption brought about by the gas guzzler tax, as it is known, will be minimal and, in our own estimation, far less than that projected by the administration.

Similarly, an outright ban on fuel inefficient automobiles will be a largely cosmetic act conserving only a minute amount of fuel at great cost in economic dislocation, employment, and loss of investment.

If one were to make an aggregate application of the fuel inefficiency tax schedule to the current industrywide swmpg, the average tax penalty would be $52 in 1978 and $111 in 1979, which when compared to the retail price of automobiles is only a marginal amount. There are few models which even now are as low as 12–14 miles per gallon.

Only 12 percent of domestic models would be subject to the largest taxes applied to cars getting that mileage. One of these penalties is $52 and the other $111, compared to an average retail price of $4,363. It can be seen that no great deterrent is imposed to the purchase of fuel-inefficient automobiles.

If we assume, on the size of these penalties, a .9 elasticity of demand for domestic automobiles, which is the most commonly accepted industry figure, there would be, overall, a decrease in demand based on the 1978 penalty of .1; for 1979, the decrease in demand would be 2.25 percent.

The estimated aggregate 2-year decline would be approximately only 219,461 units, which represents only 3.1 percent of one year's sales of automobiles.

Moreover, if these sales are transferred to cars of average economy at 17 miles per gallon, the annual fuel savings would be 643,000 barrels. 643,000 barrels of fuel amounts to 9 percent of 1 day's use in the United States.

It must be emphasized, moreover, that much of the shift in purchases created by this decline in unit sales will be transferred to the 33 domestic models which are not subject to a 1978 or 1979 tax penalty, so obviously, not all of these sales would be shifted to imports.

On page 12 of our testimony there is a table showing the impact of a fuel inefficiency tax on the sale of new automobiles.

The third point, the original administration proposal that was dropped by the Ways and Means Committee of the House, for a discriminatory rebate on domestic and Canadian manufactured automobiles is regarded by us as an intellectual absurdity that would bring about an actual increase in gasoline consumption many times the savings that would be effected by the gas-guzzler tax. Moreover, it would violate international trade agreements, including the GATT, Treaties of Friendship, Commerce and Navigation with countries such as West Germany, Japan, and Italy. It would open up the U.S.-Canadian Automotive Trade Agreeement to a revocation by the contracting party to the GATT waiver.

The most fuel-efficient automobiles sold presently in the U.S. market are imports. Of the 15 highest mileage automobiles currently sold in the United States, 14 are imports, with an average combined gasoline mileage of 39.1 miles per gallon. The only U.S.-manufactured automobile in the top 15 category is the Chevrolet Chevette.

If the proposed discriminatory rebate mechanism were instituted, there would be a substantial net fuel loss to the U.S. economy resulting from the superior fuel economy of foreign automobiles which, overall, according to EPA statistics, are averaging approximately 33 miles per gallon.

Even if a rebate were given for fuel-conserving domestic automobiles, there would be a net fuel loss to the U.S. economy. A study conducted for our industry by Harbridge House,[1] an independent research firm in Boston, concluded that the 11.9 million imported cars currently in the United States provided an annual savings of 3.2 billion gallons of fuel, or an annual savings of 76 million barrels of gasoline, due to the efficiency of these automobiles vis-a-vis their domestic counterparts.

Point four. Restricting imported automobile sales by a rebate subsidy, or other measures, would remove much of the incentive domestic manufacturers have to improve the fuel economy of their vehicles over and above the Government-mandated fleet average standards, and since the imported automobile industry has been shown to be a net contributor to employment in this country, such actions would cause an increase in unemployment, as well as the closing of hundreds of independent small businesses.

My fifth and final point, fears that either rebates or taxes on fuel-inefficient automobiles will turn over the U.S. automobile market to imports are groundless. Domestic manufacturers are becoming fully competitive in the small-car market, and by 1980 the imported automobile industry expects to be on the defensive.

Far more important than the National Energy Act in shaping the share of market held by imports is that aspect of the Energy Policy and Conservation Act of 1975 related to the inclusion of captive imports in the fleet average fuel economy standards of the domestic manufacturers until 1980.

I see my time has expired. If the chairman wishes, I will stop at this point and be open to questions.

Senator HATHAWAY. Thank you very much.

Senator Packwood?

Senator PACKWOOD. I have no questions. I have read your entire statement and the study. It is very good—some of the better testimony I have heard.

This report is especially interesting, and I congratulate you on having it done.

Mr. MCELWAINE. Thank you.

Senator HATHAWAY. Mr. McElwaine, I appreciate your testimony very much. It does give us something to consider and study.

Let me ask you, don't you think it will have any impact as far as fuel savings? Is it not also true that it will not have any impact on the industry?

The industry is complaining that it is going to hurt them a lot and not give any savings. Are not the two tied together?

Mr. MCELWAINE. The gas guzzler tax, according to our studies, as enacted by the House would have both a minimum impact on sales as well as fuel economy. We see it, as you can see from the chart we provided, as affecting no more than 236,000 cars out of a total market of over 11 million.

I would like to add at this point that that proposal by the Senate Energy Committee to ban the sale of all automobiles which do not meet the minimum standards is strongly opposed by our members because we

[1] This was made a part of the official files of the committee.

feel that this, too, would have a minimal impact on fuel conservation, but a massive impact on our industry.

It would, for example, ban all U.S. sales for certain models of the Mercedes Benz, all models of the Jaguar, certain models of the BMW, all the Rolls Royces, all the Maseratis, all the Ferraris.

These cars could no longer be sold to the United States. The total cars involved, both domestic and imported in this ban, would be 100,000 plus that could no longer be sold.

Transferring the sale of these cars to models that do meet the minimum standards would save, at the most optimistic estimates, no more than 8 million gallons of fuel annually. American drivers consume that much gasoline every 40 minutes. Yet, the proposal could affect the livelihood of as many as 1,000 American small businesses who sell these cars, and the jobs of more than 25,000 workers in these dealerships. It would put thousands of people out of work. It would close hundreds of small dealerships, to save 40 minutes of our annual fuel consumption.

It is foolhardy economy.

Senator HATHAWAY. What do you mean about elasticity of 0.9?

Mr. McELWAINE. This is the change in consumer demand for a product, according to increases, or decreases in its price, how much you affect the sale by raising or lowering the price.

Senator HATHAWAY. 0.9 of 1 percent?

Mr. McELWAINE. Yes.

Senator HATHAWAY. Thank you.

The CHAIRMAN. Let me ask you this. If the domestic producers of automobiles find it necessary to produce a smaller automobile and put less frills on it to meet these standards, you would take off the power brakes I was talking about, the power steering, the push-button windows, the air-conditioning, drastically reducing the weight of the automobile. You take away some degree of convenience, but on the other hand, you make tremendous fuel savings when you do that.

When they do those kinds of things and produce a smaller automobile with less steel and less materials, fewer flashing lights and so forth, does that not mean that we will lose jobs in automobile manufacturing plants, in any event?

Henry Ford once talked about the model cars. He said, "large cars, large profits; mini cars, mini profits."

Does that not really mean fewer jobs producing the automobile in any event, even assuming you are producing the same number?

Mr. McELWAINE. The studies we have seen on this subject, Mr. Chairman, and there are not many of them, the ones that we have seen indicate that the difference in man-hours involved in the production of small cars versus large cars is minimal. As a matter of fact, the total number of man-hours involved in the production of automobiles is slight. In the Harbridge House study they referred to a study on this subject and a statement by the vice president of Ford Motor Co. in which, I believe, he estimated the total number of man-hours involved in the production of the automobile involved as 73. There is not a great deal of difference between one car and another.

That same study referred to, in the Harbridge House report, estimated the difference in costs between a Chevrolet at the time the study was done, and Cadillac at only $300 and the bulk of that would have been material rather than labor, I believe.

The CHAIRMAN. The material needs labor, too, does it not? It takes labor to make the steel, the aluminum, and the glass?

Mr. MCELWAINE. The total number of man-hours in the study per car, including raw material production, was 100. I do not think you would see any significant change, although there would certainly be some. There would be some decline in the number of man-hours per car involved, switching from larger to smaller cars. I am not sure that it would be significant enough to become an employment factor, especially if they can sell more of the small cars at the lower prices than they can the larger car.

The CHAIRMAN. I am surprised to see you say that the average automobile requires only 73 man-hours of production.

Mr. MCELWAINE. That was a statement by a vice president of Ford Motor Co.; it is quoted in the Harbridge House study. I cannot find it very quickly.

The CHAIRMAN. It seems to me, if there is that low an estimated labor cost, that must not include the cost of producing the parts. Does that include the parts?

Mr. MCELWAINE. Everything, exclusive of raw materials.

The CHAIRMAN. If auto workers are making $10 an hour, there is only $730 worth of manpower input. If it were $15 an hour, that would still be a low figure.

Well, thank you very much. I am going to take your presentation home and study it, because I think you have a lot of good material here. You have presented us with a wealth of information that is new to some of us, including the point you just made.

Thank you very much.

Senator Matsunaga?

Senator MATSUNAGA. I do not have any questions, Mr. Chairman.

Mr. MCELWAINE. Mr. Chairman, may I make one comment?

The International Trade Commission study has been referred to in the testimony here a great deal this morning. I have written a letter to the Chairman of the ITC on that subject with a copy to you.

There is a statement in that study that the combination of the gas guzzler and rebate program will transfer over 300,000 sales from domestic to imported automobiles, with a job loss to the domestic industry of 23,000 jobs. We take strong issue with this.

Between 1972 and 1976, the domestic automobile industry's annual sales declined by almost 500,000 units, 476,000 units, to be exact, and they lost only about 11,000 jobs during that entire time.

The ITC study does not even mention the jobs in the imported car industry. The Harbridge House study that the ITC had in their hands at the time they wrote this report showed a transfer of 300,000 sales from the imported automobile business to the domestic automobile industry would increase domestic automobile employment by 20,000 jobs.

At the same time, it would decrease employment in imported automobile dealerships by 23,000 jobs, so giving an additional 300,000 sales to the domestic automobile industry would cause a net loss of employment in the United States.

This was not taken into account into the ITC study. It is not mentioned in there.

As I say, both historically and for research purposes, their figures are in dispute.

Sen. HATHAWAY. Thank you very much.

[The prepared statement of Mr. McElwaine follows:]

[The prepared statement of Mr. McElwaine follows. Oral testimony continues on p. 208.]

1. The fuel economy standards requiring the automobile manufacturers to attain a fleet economy standard of 27.5 mpg by 1985 are sufficient to achieve fuel efficient automobiles by 1985. Substantial civil penalties imposed upon the manufacturer are sufficient incentive to induce manufacturers to increase the fuel efficiency of their automobiles. Moreover, car purchasers have demonstrated in the past their realization that the purchase of fuel efficient cars is in their own economic self-interest without the necessity of a rebate.

2. The impact of the tax on fuel-inefficient automobiles is likely to be marginal. The requirement to meet fleet average fuel economy standards will be far more effective in improving automotive fuel economy. Actual fuel savings resulting from this tax would be miniscule. Similarly, an outright ban on fuel-inefficient automobiles would conserve only a minute amount of fuel, at great cost in economic dislocations, unemployment and lost investment.

3. A discriminatory rebate system which treats imported automobiles differently from domestic or Canadian-produced automobiles would violate the national treatment obligations of the United States arising under Article III of the General Agreement on Tariffs and Trade and under the Treaties of Friendship, Commerce and Navigation entered into with such countries as Japan, West Germany, and Italy.

4. A discriminatory rebate system would amount to a nullification and impairment of concessions previously negotiated by the United States. Requests by affected contracting parties under Article XXIII of the GATT that prior trade concessions granted the United States be suspended might trigger a trade war with other GATT contracting parties.

5. A discriminatory rebate system which might result in a "significant diversion" of trade or "imminent threat of diversion of trade" away from imported automobiles would "open up" the United States-Canadian Automotive Products Agreement to a revocation by the contracting parties of the GATT waiver.

6. Excluding imported automobiles from the rebate subsidy would result in a net domestic increase in fuel consumption, resulting from the superior fuel economy of foreign automobiles which overall average nine miles more to the gallon than domestic automobiles eligible for the rebate.

7. Eliminating or diluting the competition from fuel efficient imported automobiles would remove much of the incentive domestic manufacturers have to improve the fuel economy of their product. It was the competition from the Volkswagens, Toyotas, and Datsuns which induced domestic manufacturers to produce fuel efficient subcompacts, not government interference in the marketplace.

8. Imported automobile sales in the United States are a net contributor to employment in this country and shifting a significant number of purchases away from imported automobiles would cause an increase in unemployment as well as the closing of a number of independent dealer businesses.

9. Whether or not rebates and a fuel-inefficiency tax are included in the final version of the program, there is no danger of the U.S. automobile market being "turned over" to imports. By 1980 and even before, domestic manufacturers will be fully competitive in the small car field. Far more important than the National Energy Act in shaping share of market held by imports is that aspect of the Energy Policy and Conservation Act of 1975 related to the captive imports of the large U.S. automobile companies.

I. INTRODUCTION

Mr. Chairman: My name is Robert M. McElwaine, and I am Executive Vice President of the American Imported Automobile Dealers Association (AIADA). I am accompanied here today by Bart S. Fisher, Esq., of the law firm of Patton, Boggs and Blow in Washington, D.C. AIADA, which represents the independent American businessmen who sell and service imported automobiles, appreciates the opportunity to testify before the Committee on the effects of the tax and rebate provisions of the proposed National Energy Act.

Regulation—to be effective—should take into account the nature of the industry which is being regulated. In the case of automobiles, the Committee should bear in mind that this industry, more than any other, has become truly international, particularly in the postwar period. The dominant characteristic is the internationalization of production and sales. The Ford Pinto, for example, may include a transmission from Germany, an engine from Great Britain, and be assembled in Canada—yet be sold as a "domestic" U.S. automobile. A German car, the Volkswagen, has brakes by Bendix, headlamps by GE, windshield and windows by Combustion Engineering, tires from Goodyear—and the body includes magnesium from Dow and steel from U.S. Steel.

So internationalized and so diversified is the production of automobiles that one is justified in asking, "Just what is an import?" Some cars sold as imports may represent more American man-hours than some labeled a domestic product.

The policy implications of the internationalization of the world automobile industry are profound. With respect to trade policy, the implication to be drawn is that the removal of all artificial barriers to automotive trade between nations would bring the advantages of competitive efficiencies to all consumers and ensure the continuing growth and expansion of this vital industry. A first step towards a worldwide free trade area in automobiles was taken in 1965, when the United States-Canadian Automobile Agreeemnt was signed. AIADA looks forward to the day when there are no trade barriers in the world automobile market.

Presumptively, then, Mr. Chairman, AIADA has a bias against regulation of the world automobile economy. Unfortunately, the gas-guzzler tax and rebate provisions of the proposed National Energy Act would further clog the channels by introducing a series of agreements with foreign countries limiting the availability of rebates. Nevertheless, if the tax and rebate provisions could be justified on other grounds, we would support them. Like Pinocchio's nose, however, our catalogue of complaints grows longer and longer the more we study the tax and rebate program.

In summary, AIADA believes that:

(1) The gas-guzzler tax and rebate program is not needed to attain additional fuel conservation;

(2) the impact of the tax on fuel-inefficient automobiles is likely to be marginal;

(3) the granting of rebates for fuel-efficient automobiles would be counterproductive, and should be eliminated from the proposed National Energy Act; and

(4) whether or not rebates are included in the final version of the program, there is no danger of the market being "turned over" to imports.

II. THE PROPOSED TAX AND REBATE PROGRAM IS NOT NEEDED TO ATTAIN FUEL CONSERVATION

The most salient fact about the proposed gas-guzzler tax and rebate program is that it is not needed to attain fuel-efficient automobiles. This objective is already being met by the Energy Policy and Conservation Act of 1975 (Public Law 94–163, December 22, 1975) (EPCA). The EPCA establishes mandatory average fuel economy standards, effective with model year 1978, requiring each manufacturer and importer to attain a fleet average fuel economy of 18 miles per gallon (mpg) in model year 1978; 19 m.p.g. in model year 1979; 20 m.p.g. in model year 1980; and 27.5 m.p.g. in model year 1985 and thereafter. These are essentially the same fuel efficiency standards as those mandated by the proposed Act. Domestic manufacturers under the 1975 Act have already made substantial progress toward these goals. General Motors, for example, has achieved a 50 percent improvement in the gasoline efficiency of its models since 1973. Overall, domestic 1977 models average 18.6 m.p.g., up from 14 m.p.g. only 2 years ago.

The Energy Policy and Conservation Act alone is capable of inducing automobile manufacturers to increase the fuel efficiency of their automobiles. The Act imposes substantial civil penalties directly upon the manufacturer for failing to meet fuel economy standards. This is a penalty directed primarily to the entity most capable of achieving desired fuel economies: the manufacturer. Instead, the proposed Act undertakes to indirectly achieve the same result by a scheme of gas-guzzler taxes and rebates eventually paid to the purchasers of new domestically-manufactured passenger vehicles whose fuel economy exceeds the applicable fuel economy standard.

The auto efficiency standard and penalty under the EPCA operate in many respects as an indirect auto inefficiency tax and rebate for any auto manufacturer whose fleet average gas mileage is at or below the standard. For such a manufacturer, the sale of an additional inefficient car will lower the manufacturer's fleet average fuel efficiency and increase his penalty, while the sale of an additional efficient car will raise the fleet average efficiency and lower the penalty.

Although the penalty under EPCA is $50 for each car in the fleet for every mile by which the fleet average falls below the standard, the implicit penalty on an inefficient car is much more than $50. First, since the penalty is nondeductible for tax purposes, it is the equivalent of increasing the deductible costs by almost $100 per car. Second, when the penalty is allocated only to the inefficient cars (as opposed to the entire fleet), it far exceeds the post-income tax cost of $100 per car per mile below the standard. Because inefficiency is measured in terms of gallons of gas consumed over any assumed number of miles, the penalties allocable to the more inefficient cars are quite substantial. To measure gallons of gasoline consumed by a manufacturer's fleet, the fleet average is computed under a formula employing the harmonic mean. Consequently, the contribution of a very inefficient car to not meeting the fleet standard and causing the $50 per car penalty to be imposed on the entire fleet is substantially greater than the contribution of one slightly below the standard.

One study [1] has calculated that the existing $50 penalty for a manufacturer is equivalent to the following auto inefficiency tax and rebate schedule compared to the proposed tax and rebate proposal:

TABLE 1.—SWEENEY ANALYSIS OF MANUFACTURER PRICING RESPONSE TO CURRENT LEGISLATION VERSUS PROPOSED GAS-GUZZLER TAX AND SUBSIDY

	Current law: incremental implicit taxes - rebates (−) standards) [1]	Manufacturer costs (implicit (+) or rebates from current	Proposed (implicit taxes (+) or rebates (−) from current standards)	
	1980	1985	1980	1985
New car miles per gallon:				
10	2,000	4,183	666	2,488
15	667	2,292	333	1,603
20	0	1,031	0	733
25	−400	275	−199	219
30	−667	−229	−333	−121
35	−857	−589	−428	−362
40	−1,000	−859	−473	−493

[1] In calculating the manufacturer's incremental costs, a 50-percent corporate income tax rate is assumed. These figures are the pretax cost equivalent to the non-tax-deductible civil penalty of current law. This table is based on the assumption that the manufacturer's fleet is just below the applicable mileage standard. Computations are then made with respect to the hypothetical additions of cars both failing to meet the standard and exceeding the standard.

As the table indicates, the proposed tax and rebates would simply add on lesser layers of levies and rebates to current implicit taxes and rebates in effect under the EPCA. AIADA believes that this is an unnecessary exercise, and should not be undertaken, especially in light of the progress that has been made already towards meeting the standards established by the EPCA.

III. THE IMPACT OF THE PROPOSED TAX ON FUEL-INEFFICIENT AUTOMOBILES

A. This section analyzes the impact of the proposed tax on fuel-inefficient automobiles. The long-term impact of the program is indeterminate; through 1980, however, the impact of the program is likely to be very marginal.

In 1977 the domestic sales weighted miles per gallon (swmpg) was 17.7. This was an increase from 1976 swmpg of 16.8 and 1975 swmpg of 15.6.[2] The swmpg of the major U.S. manufacturers for 1977 is broken down as follows:[3]

[1] James Sweeney, "The Impact of the President's Proposed Gasoline Tax and Gas-Guzzler Tax on Gasoline Consumption", Department of Engineering-Economic Systems, Stanford University, May 13, 1977, p. 9.

[2] Staff of the Joint Committee on Taxation, 95th Cong., 1st sess., Report on Energy Tax Proposals Relating to Transportation at 9 (committee print 1977) (Precontrol to 1977, new cars only).

[3] *Id.* at 11. See appendix for complete table.

American Motors	19.2
Chrysler	16.6
Ford	17.1
General Motors	18.4

If one were to make an aggregate application of the fuel inefficiency tax schedule to the current industrywide swmpg, the average tax penalty would be $52 in 1978 and $111 in 1979, which when compared to the retail price of automobiles is only a marginal amount. There are few models which even now are as low as 12–14 miles per gallon. When domestic models are broken down into subgroups by engine size and transmission,[4] only 12 percent would be subject to the largest taxes applied to cars getting that mileage.[5] When the average tax penalties of $52 and $111 are compared to an average retail price of $4,363,[6] it can be seen that no great deterrent is imposed to the purchase of fuel-inefficient automobiles. The average 1978 rebate would constitute only 1.2 percent of the average price; the 1979 penalty only 2.5 percent. Assuming —0.9 elasticity of demand for domestic automobiles,[7] there would be overall a decrease in demand based on the 1978 penalty of .1 percent; for 1979, a decrease of 2.25 percent.

The following table shows an estimated decline over a 2-year period (1978–1979) of sales of domestic cars by size classification resulting from the imposition of the fuel inefficiency tax. The estimate is a crude arithmetical calculation and is probably an overestimate as: (1) average retail prices will increase over the next two years,[8] and (2) mileage averages are bound to improve. The estimated decline figures were calculated by the following method:

(1) The percentage increase of the average price for each category represented by each year's penalty (based on average mpg) was computed; and

(2) the decline in demand induced by a —0.9 elasticity of demand was then applied to the 1977 sales figure for that category, for each year's estimated decline, and the two resulting figures added together.

The estimated aggregate 2-year decline would be approximately only 219,461 which represents only 3.1 percent of one year's (1976) sales.

It must be emphasized, moreover, that much of the shift in purchases created by this decline in unit sales will be transferred to the 33 domestic models not subject to a 1978 or 1979 tax penalty (and theoretically eligible for a rebate if that portion of the Administration's proposal is passed). Obviously, then, not all sales will be shifted to imports.

B. AIADA would like to take this opportunity to express its strong opposition to the proposal approved by the Senate Committee on Energy that would ban the sale of vehicles in the United States that do not meet certain minimum fuel economy standards. We oppose this proposition on the grounds that it will have a minimal impact on fuel conservation, at tremendous cost in employment and economic dislocation as well as from a philosophic standpoint in that it represents an unwarranted intrusion by the Federal Government into the marketplace.

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[4] The mileage category breakdown used by the EPA.

[5] 1978 taxes respectively: $449 (12–13 mpg), $345 (13–14 mpg) and $256 (14–15 mpg). 1979 taxes respectively: $553, $436, $339.

[6] Excluding the prices of the six luxury models which were high above the mode. Based on 1977 Manufacturers' Suggested Retail Prices. Source: Automotive News 1977 Market Data Book Issue at 80.

[7] The three major studies of the price elasticity of demand for automobiles are those of: (1) D. B. Suits, "The Demand for New Automobiles in the United States 1929–1956," Review of Economics and Statistics, XL (August, 1958), pp. 273–80; (2) G. C. Chow, Demand for Automobiles in the United States. Amsterdam: North-Holland Publishing Co., 1957; and (3) C. F. Roos and Victor von Szeliski, "Factors Governing Changes in Domestic Automobile Demand," The Dynamics of Automobile Demand (New York: General Motors Corp., 1939) pp. 20–99. The results of these studies are summarized below.

Study:	*Price elasticity*
1. Suits	—0.6
2. Chow	—1.2
3. Rose and von Szeliski	—1.3

The study of Roos and von Szeliski deals exclusively with pre-World War II data, and is inappropriate for post-World War II analysis. Opinion differs on whether the Suits or Chow analysis is appropriate. *See* Report of the Subcommittee on Antitrust and Monopoly of the Committee on the Judiciary, U.S. Senate, 85th Cong., 2d sess. Nov. 1, 1958, "Chapter 6: The Demand for Automobiles". Accordingly, AIADA will rely on a price elasticity of demand of —0.9, which is equi-distant between their two estimates.

[8] Automotive News found that 1977 model prices rose an average of $265.69 or 5.65 percent over the final prices of 1976 models. Automotive News, *op. cit.*, at 80.

TABLE 2.—IMPACT OF THE FUEL INEFFICENCY TAX ON THE SALE OF NEW AUTOMOBILES IN 1978 AND 1979 [1]

Size classification	Average 1977 [2]	Average retail price [3]	Average 1978 penalty	Average 1979 penalty [4]	Estimated decline [5]
Subcompacts	25.4	$3,083	0	0	0
Compacts	18.04	3,448	0	$52	29,094
Intermediates	16.7	4,694	$112	176	104,504
Standards	16.1	5,693	112	176	41,809
Total 2-year estimated decline, 219,461.					
Percentage of 1976 sales represented by this figure, 3.1 percent.					

[1] See appendix III. The above table assumes static conditions in sales volume and average price.
[2] EPA miles per gallon for that size.
[3] Based on 1977 suggested retail prices.
[4] Based on "Tax and Rebate Schedule for New Car Sales," in staff of the Joint Committee on Taxation, 95th Cong., 1st sess., Report on Energy Tax Proposals Relating to Transportation 20–21 (committee print, 1977).
[5] Purchases in that size class based on 1976 sales (combined 1978 and 1979).

If the government has the power to tell the consumer that he may not buy a luxury automobile, on grounds of energy conservation, may not such powers extend to other energy-consuming products—such as houses. Surely the government would shrink from proscribing the construction of new homes with more than three bedrooms on the grounds that this would constitute an unacceptable intrusion into consumer choice. Yet, such an act would have as much validity as mandating an end to production of automobiles that cannot meet certain minimum fuel economy standards.

Moreover, the banning of U.S. sales for such automobiles as the Mercedes-Benz, Jaguar, BMW, as well as certain domestic models, would have an impact on fuel consumption that could only be described as trivial. We estimate that no more than 100,000 new cars annually would be affected. Transferring the sale of these cars to models that do meet the minimum standards would save, at the most optimistic estimates, no more than 8 million gallons of fuel annually. American drivers consume that much fuel every 40 minutes.

Yet, the proposal could affect the livelihood of as many as 1,000 American small businesses, as well as the jobs of more than 25,000 workers in these dealerships. To put thousands of people out of work, close hundreds of small businesses and impact adversely on all the communities wherein these businesses are located, merely to save 40 minutes of fuel usage each year, would appear to us to be a foolhardy economy.

IV. THE GRANTING OF REBATES SHOULD BE ELIMINATED FROM THE PROPOSED NATIONAL ENERGY ACT

The tax on fuel-inefficient automobiles can be expected to have a marginal impact; the granting of a rebate for the purchase of a fuel-efficient automobile, however, is an intellectual absurdity and should be eliminated from the proposed National Energy Act.

The rebate proposal poses a logical conundrum: To maximize fuel efficiency, all fuel-efficient automobiles should be able to qualify, whether imported or domestic, on a basis of full equality of opportunity. This is because 14 of the 15 most fuel-efficient automobiles are imports. While not seeing the limited utility of paying people to buy cars, the Administration was offended by the concept of paying people to purchase foreign cars. Accordingly, the rebate, as originally announced in the Administration program, would be confined to domestic and Canadian-origin automobiles, and would only be available for purchases of imports in accord with executive agreements possibly entered into with exporting countries. Unfortunately, this reduces fuel efficiency, creates additional unemployment in the United States and harms U.S. consumers.

Moreover, a discriminatory rebate system which treats imported automobiles differently from domestic or Canadian-produced automobiles would violate international agreements and treaties agreed to by the United States.

A. The National Treatment Obligations of the GATT

The rebate would violate the national treatment obligations of the General Agreement on Tariffs and Trade (GATT). The giving of rebates for the purchase of solely domestic or Canadian-produced automobiles is a clear violation of Article III, paragraph 2 of the GATT, which provides that imported goods must be accorded the same treatment as goods of local origin with respect to matters under government control, such as internal charges and internal taxation.[1] The GATT clearly defines the national treatment obligation with respect to internal charges and taxes:

The products of the territory of any contracting party imported into the territory of any other contracting party shall not be subject directly or indirectly, to internal taxes or other internal charges of any kind in excess of those applied, directly or indirectly, to like domestic products. Moreover, no contracting party shall otherwise apply internal taxes or other internal charges to imported or domestic products in a manner contrary to the principles set forth in paragraph 1.[2]

Denial of a rebate for the purchase of an imported fuel-efficient automobile forces the domestic purchaser to pay a substantial premium for a like imported product. It is an internal charge applied only to imported products with the express purpose of protecting U.S. production, and in effect is an indirect tax upon the purchase of the imported automobile, while domestic products are exempted from this internal charge. Article III:2 prohibits the imposition of both direct and indirect taxes on a discriminatory basis.

Cases which have arisen under the general national treatment obligation of Article III indicate that granting special credit facilities for the purchase of domestic goods only violates the national treatment obligation.[3] Although Article III, paragraph 8(b) specifically exempts the payment of subsidies "exclusively to domestic producers" rebates to purchasers are not within the scope of this exemption. The critical distinction between an improper advantage and a permissible production subsidy is that the former is given to the purchaser and the latter is granted to the producer.[4]

These cases indicate that internal taxes and charges should not be discriminatorily applied, directly or indirectly, against imported products so as to place imports at a competitive disadvantage. The denial of a rebate to the purchaser of an imported automobile is thus an indirect purchase tax that violates the United States' national treatment obligation under the GATT.

B. Treaties of Friendship, Navigation and Trade

Any discriminatory subsidy for domestic automobiles that excludes imports similarly would contravene the national treatment articles of our treaties with the producing countries involved. The national treatment obligations of the United States set forth in paragraph (1) of Article XVI of our Treaties of Friendship, Commerce and Navigation with Italy, Japan, and West Germany require that imported products be accorded treatment "no less favorable" than the treatment accorded domestic products. Since the rebate would not be applied to the purpose of imported automobiles, such a discriminatory measure would violate the national treatment obligations under these treaties.

The Administration attempts to salvage the rebate scheme from the national treatment problems it creates by stating that rebates may be available on the basis of executive agreements entered into between the producing countries and the United States. Nevertheless, it is not at all clear that such agreements could be negotiated. Even should any agreements be entered into, the United

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[1] See in general, Jackson, World Trade and the Law GATT, Chapter 12 (1969).

[2] GATT, Article III:2 Paragraph 1 states:

The contracting parties recognize that internal taxes and other internal charges, and laws, regulations and requirements affecting the internal sale, offering for sale, purchase, transportation, distribution or use of products . . . should not be applied to imported or domestic products so as to afford protection to domestic production.

[3] See Great Britain's complaint against France for the latter's practice of refunding to purchasers 15% of the cost of only domestically produced agricultural machinery. GATT Doc. L/695 (1957). Also the British complaint also against Italy's special fund to grant special credit terms to Italian-manufactured agricultural machinery. The GATT report recommended that the credit facilities be made available on the purchase of agricultural machinery, whatever its origin. GATT Doc. L/838 (1958). The refund went to the firm just as a tax deduction or exemption would, but it was tied to the purchase of domestic goods. See also reference to preferential credit facilities given by the Greek Governmnt on domestic goods. GATT Doc. L/740 (1957). Jackson, World Trade and the Law of GATT 285, 287 (1969).

[4] See Jackson at 287. A GATT Panel noted that the intent of the draftsmen "was to provide equal conditions of competition once the goods have cleared through customs." GATT, 7th Supp. B 15D60 at 64 (1959). See also the examples cited in note 3 above.

States would still be in violation of its national treatment obligations under the GATT and under its FCN treaties.

C. Nullification and Impairment of Previously Negotiated Tariff Concessions

Apart from violating the national treatment obligations of the GATT, the discriminatory rebate arrangement would amount to a nullification and impairment of previously negotiated concessions. In the 1963 Kennedy Round of tariff negotiations, the United States agreed to reduce the pre-Kennedy Round tariff of 6.5 percent and thus "bound" its tariff on automobiles to 3 percent. The denial of rebates to imported automobiles amounts to a nontariff barrier which as an internal charge increases the price to domestic consumers (in the form of the foregone rebate) and thus impairs the prior concession. Any contracting party which has received a tariff concession has the right to expect that such concessions will not be impaired in the future by the grantor.

Under Article XXIII of the GATT the other affected contracting parties such as Germany and Japan could request that the application of prior trade concessions made to the United States be suspended. Trade concessions due the affected countries on U.S. exports would exceed $5 billion. Under the circumstances, one is justified in asking: "What U.S. industry is the Administration prepared to sacrifice in order to pay this rebate?" In other words, an improperly structured tax/subsidy mechanism could trigger a trade war, a trade war in which the other contracting parties of the GATT would be justified in withdrawing trade concessions from the United States. A note verbale from the European Economic Community to the Special Representative for Trade Negotiations has stated that the EEC would consider a discriminatory rebate measure as a new barrier to trade and as contrary to both the spirit and letter of the GATT.[5] Such a protectionist measure also would undermine the present Multilateral Trade Negotiations and destroy the foundation of the existing OECD pledge not to engage in unilateral trade restrictions to combat the energy crisis. In his testimony on Monday, May 16, Assistant Secretary of State Julius L. Katz stated that the energy challenge requires global cooperation, that the United States and its industrialized allies must cooperate in energy for our mutual benefit or energy will become a divisive issue that undermines our collective strength. A discriminatory rebate mechanism will defeat those very objectives.

D. The United States-Canadian Automotive Products Agreement

Granting of rebates to domestic and Canadian-produced automobiles on a discriminatory basis could undermine the United States-Canadian Automotive Products Agreement of 1965. At the time the United States-Canadian Automotive Products Agreement was negotiated, it was widely recognized that the Agreement, by providing different tariff treatment for the automobile products of different countries, violated the Most-Favored-Nation principle in Article I of the GATT. Accordingly, the United States sought, and received, a waiver from the Contracting Parties of the GATT under Article XXV(5). The Contracting Parties, after serious misgivings, finally granted the waiver on December 20, 1965. It was granted on the condition that there would be no significant diversion of trade in automobiles away from the historical patterns of the world automobile market. The waiver states:

In the event the parties to consultation in accordance with paragraph 2 above agree there has been a significant diversion or is an imminent threat of diversion of trade, the waiver shall terminate in accordance with paragraph 5, with respect to the automotive product or products in question. If the parties to consultation fail to reach agreement, either may refer the question whether there has been a significant diversion of trade to the Contracting Parties. *If the Contracting Parties decide that the requesting country has a substantial interest and that there has been a significant diversion or is an imminent threat of diversion of trade, the waiver shall terminate in accordance with paragraph 5, with respect to the automotive product or products in question.* (Italic supplied.)

The proposed unlimited rebate to domestic and Canadian-produced automobiles would result in a "significant diversion" or "imminent threat of diversion of trade." In the bid-1960's U.S. car makers all but abandoned the small car market to foreign cars. The share of imports in the small car market rose in the 1960's, and from 1971–1975, as a result of a rise in gas prices, recession, pollution regulations, a shift to economical foreign automobiles occurred. The following table illustrates the historical trend in the import market since 1968:

[5] Note verbal from the Delegation of the Commission of the European Communities to Ambassador Robert S. Strauss, Special Representative for Trade Negotiations, April 29, 1977.

Year	Imported car sales (in units)	Percent of total market		
		Domestic small car	Imported cars	Total domestic and import small car
1976	1,449,300	34.0	14.8	48.8
1975	1,577,000	34.4	18.3	52.7
1974	1,403,035	32.7	15.7	48.4
1973	1,770,000	27.4	15.2	42.6
1972	1,597,448	23.7	14.4	38.1
1971	1,554,600	23.4	15.1	38.5

Source: Automotive News 1977 Market Data Book Issue and Ward Automotive Yearbook.

The denial of a rebate to foreign manufactured cars save under an executive agreement designed "so that domestic automobile manufacturers are not disadvantaged vis-a-vis foreign automobile manufacturers under the tax rebate system," [7] would reverse this historical trend, presumably subjecting rebates on imported automobiles to limited negotiated levels. Trade would be directed towards U.S.- and Canadian-produced automobiles. Accordingly, the discriminatory rebate subsidy would "open up" the Agreement to a revocation of the GATT waiver by other contracting parties such as Japan and West Germany, which would justifiably feel that a "substantial diversion of trade" would result from the proposed rebate program. Moreover, the waiver, by its own terms, would be ended whenever there is a "significant diversion or is an imminent threat of diversion of trade" in automobiles and parts.

E. The Import of the Rebate

1. *Rebates and Domestic Automobiles.*—Even should a fuel efficiency rebate be tied to the purchase of both domestic and imported automobiles meeting the fuel efficiency standards, imported models would not be the sole beneficiaries of the program to the disadvantage of domestically-produced models. The present National Energy Act fuel economy standards and Environmental Protection Agency 1977 combined mileage per gallon figures indicate that thirty-three current U.S.-produced models, at 1977 gas mileage levels, would be presently eligible for both a 1978 and 1979 rebate. Appendix III contains a table, broken down by size classification, manufacturer and model (further broken by engine size and type of transmission) which, based on mileage figures and utilizing the International Trade Commission's Master Sheet Set of Assumptions compiled for this study, would be eligible for a rebate. Eligible domestic automobiles do not fall solely in the subcompact or compact size classification. All U.S.-produced subcompacts would be eligible for a 1977 and 1978 rebate. Among eligible compacts are the American Motors Hornet and Pacer, the Chevrolet Nova, the Ford Granada, and the Plymouth Volare. Four mid-size models are eligible. In addition, three full-sized models are eligible for the rebate: the Buick Le Sabre, the Oldsmobile Delta 88, and the Pontiac. Furthermore, eight station wagons (six small-sized and two mid-sized) are similarly eligible.

The U.S. automobile industry is not faced at the outset with an inability to compete with imported models within a scheme of "gas-guzzler" taxes and rebates. First, 33 models comprising 20.85 percent of 1976 U.S. and Canadian production would be currently eligible for a 1978 rebate without technological modifications. Second, many models have mpg levels almost equalling qualifying levels. Third, since the announcement of the energy plan in April, automobile buying patterns have had a mixed pattern: Both small cars (including imports) and large car sales have increased. The Vice President of Potamkin Cadillac Corporation, the nation's largest single Cadillac dealer, reported that "[W]e've felt no impact at all since the President's [energy] message, although it was a little slow in the days just before it." [10]

[7] Committee Print prepared for the Committee on Ways and Means, "Section by Section Description of H.R. 6831, The Administration's Tax Proposals Relating to Energy", at 10 (May 13, 1977).

[10] In May 1977 the import share of the U.S. market rose to 20 percent, the largest percentage increase from 1976 levels was captured by the Dodge Colt (a 144.6 percent increase over May 1976 levels and the Chrysler-Plymouth Arrow (which registered a 166.1 percent increase). Toyota registered 67.1 percent, Datsun 82.3 percent, Fiat 16.9 percent, and Honda 142.8 percent. New York Times, "VW in Bid for 5 Percent of Market, Plans to Build 2d U.S. Plant." (June 15, 1977).

In April, 1977, domestic car sales rose 4.3 percent over the month before.

Domestic manufacturers would not face the enactment of a combination tax-and-rebate statute without the ability to achieve the required fuel-efficiency levels within the statutory scheme. Automobile manufacturers have entered into a major program to sharply improve the fuel economy of their cars. General Motors initiated a massive corporate downsizing effort on its big cars [11] with the 1977 models. Nearly all of GM's 1977 standard sized models underwent a radical reduction in size and weight, primarily to increase gas mileage. Some models shed up to 900 pounds (GM cut an average of 700 pounds off its big cars) and more than 12 inches in overall length.[12] Use of smaller engines, lighter materials and revised drive trains also contribute to significant gains in fuel economy over 1977 models. GM's intermediates are currently undergoing the same transformation. GM's X-body compacts will be "downsized" in mid-1979; its subcompacts the year thereafter.

At Ford Motors and Chrysler, downsizing provisions are on a slightly different timetable. Nonetheless, Automotive News reports, all car lines at the Big Three will have been resized by the 1981 model year.[13]

Engines may also change significantly. In 1978, GM will introduce a diesel V–6 in some Oldsmobiles [14] and is expected to produce 25 percent better fuel economy. Pontiac and Chevrolet are said to be testing diesel engines as well. Ford is planning to produce a system for conventional engines that could help mileage by at least 10 percent by shutting off some of the cylinders in the engines when not needed (as when slowing down or cruising at a steady speed). Ford is also developing a "stratified charge" engine in which gasoline is burned in dense and thin layers for greater efficiency. GM plans to drop its two biggest V–8's.

Other technological developments that over time could add up to a 15 percent mileage gain would be more efficient transmissions and some automatic transmissions with gas-serving overdrive gears. Ford and GM are experimenting with turbochargers. Buick will turbocharge its 231 V–6 in 1978.[15]

2. *Rebates and Imported Automobiles.*—If rebates were to be implemented on a basis that discriminated against imported automobies, the following results would occur:

(a) Unemployment in the United States would be increased;

(b) The significant investments in the imported automobile industry in the United States would be harmed;

(c) Consumer welfare would be lowered; and

(d) Discrimination against imported automobiles would result in a net domestic increase in fuel consumption.

The methodology employed to analyze this issue by Harbridge House, an independent research institution, was based on an analysis of a shift of 300,000 unit sales from imports to domestic purchases. Another study, by Charles Rivers Associates, Inc., also is relied upon to describe the impact of policies that might discriminate against imported automobiles.

a. Impact on Employment

Imported automobiles sales in the United States are a substantial contributor to employment and shifting a significant number of purchases away from imported automobiles would cause an increase in unemployment. Employment generated by the import of motor vehicles into the United States is substantial. According to the Harbridge House [16] study, approximately 127,230 people are directly employed by the dealers and distributors of imported automobiles, of whom 92 percent are in the industry organization and the remaining 8 percent

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[11] Generally, for every 400 pounds of weight removed, a car's mileage will raise about one mpg if everything else is left unchanged. Such changes as less powerful engines usually are made at the same time, however, yielding larger gains. See Wall Street Journal, "You Want to Avoid a Gas-Guzzler Tax? You Could Try a Large Size Buick," at 1, 16 (April 25, 1977).

[12] Automotive News 1977 Market Data Book Issue at 24; Wall Street Journal, *id.* at 16, column 1.

[13] Automotive News at 26.

[14] Though it has not yet announced it, a diesel will be put in the Cadillac Seville in 1978. Wall Street Journal at 16, column 2.

[15] Domestic automobile manufacturers have in the past relinquished the market for the smallest fuel-efficient cars to the import care industry to concentrate on selling larger and luxury cars which earn more profit per unit. A Ford executive reported that a much greater profit margin from selling 20,000 Versailles than 100,000 Fiestas could be made both by Ford and its dealers. Motor News Analysis at 2 (April 1977).

[16] The Imported Automobile Industry: An Assessment of Key Aspects of Its Impact on the U.S. Economy and the American Consumer. Harbridge House, Inc. (December 1976).

in the importing and wholesaling sectors.[17] From 1969 to 1975, employment in the imported automobile sector increased at a considerably more rapid rate than the industry's current sales,[18] in effect representing a growth in the industry's degree of labor intensiveness, especially at the dealer level where unemployment went from 6.4 jobs per 100 units sold in 1969 to 8.2 jobs in 1975.

The study reports that the imported automobile industry as a whole is expected to continue to expand, particular in terms of employment, for several more years. The total number of automobiles on the road is expected to increase for some more years,[19] with consequent increased demand for more personnel for maintenance, repair and servicing work, as well as for used car transactions.

The indirect employment effects created by the imported automobile industry should also be taken into account. Approximately 7,200 port jobs are estimated to be totally dependent on the present level of import traffic. Although difficult to quantify precisely, manufacturers of imported automobiles import approximately $50 million in parts and accessories from the United States solely for installation on vehicles destined for the U.S. market, and employment in this sector should also be computed into the employment level created by imported automobiles. Harbridge House calculated [20] that 230 jobs in the parts and accessories industries and an additional 160 jobs among suppliers to that industry depend upon a $10.5 million amount of shipments.

Gains and Losses in Domestic Employment.—What would be the impact on domestic employment if: a) A significant number of purchases of imported cars were shifted to domestic automobiles; b) all import purchases were shifted to domestic purchases, in an aggregate sense?

Net Employment Effects of a Significant Shift in Purchases from Imported to Domestic Automobiles.—The Harbridge House Study categorized as a "significant shift" in purchases of imports a unit decrease of 300,000. In part this figure is based upon the 1973–1974 unit decline of 313,600 units. Furthermore, the actual historical experiences of the American automobile industry during the past 14 years. During six of those years [21] the number of automobiles manufactured in U.S. factories increased by 300,000 or more units: those years were the basis for the analysis. Data exist for the 1973–1974 period of decline.

The assumptions upon which the net employment effects were derived from a decrease in import sales were the following:

That all purchases of imports would be shifted to domestic car purchases;

That there are .035 incremental jobs in the motor vehicle industry per incremental passenger manufactured (see table in Appendix IV);

That based on Department of Commerce input-output tables for 1963, 1966 and 1967, external inputs are approximately 40 percent at present,[22] for purposes of calculation; and

A conservative estimate that in terms of total man-hours, both inside and outside the automobile industry, 98 man-hours are embodied in each incremental car produced.

Estimated Employment Losses in the Imported Automobile Industry.—In the first year a 300,000 drop in new vehicle sales could be expected to reduce importer-distributor employment by 10 percent, representing a total of 1,080 jobs based on 1975 employment figures. It is unlikely that a drop of 300,000 unit sales (21% of 1975 volume) would cause a proportional decrease in importer-distributor employment because that aspect of employment relating to the overall vehicle population (e.g., parts, service, maintenance) would decline comparatively slowly as new unit sales declined.

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[17] These figures take into account import-associated employment in retail establishments that may sell both imported automobiles and domestic brands; they exclude, however, any employment associated with captive imports.

[18] For example, while the number of units sold (excluding captive imports) rose by 44 percent from about 1.0 million to 1.4 million during this period with some year-to-year fluctuations, total jobs increased 80 percent. See Harbridge House Study, supra note 16, at 8, 9–11.

[19] Imported automobiles in operation in the United States are still relatively young, reflecting the increase in imported new car sales in recent years. Sixty-one percent of imports operating in 1975 were 1971 or newer models (as compared to an average of 47 percent for all cars in use, domestic and imported cars). Consequently, the number of imported vehicles on the road will very likely continue to increase for some years more as they have done in the past.

[20] Based on the U.S. Commerce Department's U.S. Industrial Outlook 1976 and on Department of Labor employment statistics. Shipments per employee in the U.S. motor vehicle parts and accessories industry overall are $46,203.

[21] 1962, 1963, 1965, 1968, 1971, and 1973.

[22] In 1963 external inputs represented 37.4 percent of the total outputs of the motor vehicle industry; 1966, 39.2 percent, and in 1967 38.3 percent.

By the second year of a new vehicle sales decline of 300,000 representing a fairly permanent condition, employment among imported automobile dealerships would drop by 20,300. Sales employment (salaries depending upon commissions) would not declease more than proportionately). Much of vehicle service on imported automobile sales involves relatively new vehicles (e.g., warranty work) and preparing new cars for delivery. By the second year of a drop in sales, the decline in employment could be fully proportional.[23] Parts and accessories is one of the most stable areas of an automobile dealership: Employment levels are relatively low and parts and accessories activity is unlikely to be affected in the short run.

Approximately 1,510 port jobs would be lost. The number of jobs in the parts and accessories industry (which ship to manufacturers of imported automobiles for installation of these items in vehicles imported into the United States) and suppliers to that industry which would be affected are 390. Total direct and indirect jobs related to the manufacture of parts and accessories for installation at U.S. dealerships affected by a shift in purchases would be 330.[24]

TABLE 3.—ESTIMATED DECLINE IN IMPORTED AUTOMOBILE DEALERSHIP EMPLOYMENT CAUSED BY A 300,000 DROP IN NEW VEHICLE SALES

Dealership department	Approximate percent of dealership employment [1]	Number of dealership jobs	Effect of 300,000 unit drop in new vehicle sales (percent)	Estimated job loss
Sales	15	17,500	−21	3,680
Service	60	69,900	−21	14,680
Parts	10	11,700	None	
Administrative	15	17,500	−11	1,930
Total				20,290

[1] Based upon data provided by several importing organizations.

Estimated Increase in Employment in the Domestic Automobile Sector.—Based upon the assumptions set forth at page 22 *supra*, the study reached the following estimates:

Incremental jobs within the automobile industry (manufacturing)	10,500
Incremental jobs in the supplying industries	7,040
Total manufacturing-related jobs	17,540

The estimated increase in employment among dealers who sell and service domestic automobiles would be 3,000 in domestic dealerships, primarily in the small car sales force. Though one would expect a larger increase, historical data show that in 1971 when the unit sales increase was nearly seven times 300,000, the number of jobs slipped by 5 percent; in 1973 unit sales increased to close to three times that number, but jobs increased by less than 2 percent.

Nevertheless, the above estimates are based on the assumption that all purchases would be shifted to domestic automobiles. This would not be the case for two reasons: (1) Sales of many foreign sports and specialty cars that are luxuries for some Americans would not be replaced by sales of domestic-made vehicles, and (2) an econometric study concluded that the gain in demand for domestic cars would be moderated by the probable increase in the price accompanying the demand shift.[25]

[23] Actual experience during prolonged dock strikes when a four-to-five month shutdown resulted in a 25 percent decrease in service volume at imported automobile dealerships, dependent on struck ports, supports this viewpoint.

[24] Although not possible to predict at this point, the loss in employment that would result in the reduction in U.S. exports that would accompany inevitable retaliation by our trading parties must be taken into account. The loss in employment would probably not be confined solely to the automobile sector.

[25] Charles Rivers Associates, Inc., Impact of Trade Policies on the U.S. Automobile Market, Prepared for the Bureau of International Labor Affairs, U.S. Department of Labor, at 338 (October 1976). If a price increase in imports were simultaneously induced by the use of a 10 percent tariff (denying a rebate for the purchase of imports would act as a tariff, seee pp. 37, 38), the predicted effect would be a 3.325 percent increase in the domestic price, assuming a competitive industry. *Id.* at 208.

Net Employment Effect.—The estimated gains and losses in U.S. employment that would come from the transfer of 300,000 units of new vehicle sales are summarized as follows:

	Domestic employment	
	Gain	Loss
Manufacturing	17,540	720
Importing-distribution		1,080
Retailing	3,000	20,290
Ports		1,510
Total	20,540	23,600

Source: A predicted net employment loss of 3,060 jobs would occur.

b. Impact on Investment

In 1975 the imported automobile industry's payroll was $1.48 billion, of which 90 percent was attributable to the dealer organization and the remaining 10 percent to the importing and wholesaling sectors. There are currently approximately 4,850 American business enterprises that sell and service imported automobiles. The estimated total annual sales volume in 1975 of imported automobile dealers was $11.6 billion. From 1969 to 1975 as the number of imported automobiles—excluding captive imports—increased by .44 percent, the net investment in the imported automobile industry grew by 98 percent and the industry's total assets grew by 155 percent to $4.2 billion. As for assembly facilities, international production costs, transport costs, and economies of scale suggest that foreign manufacturers may find it economical to establish assembly facilities in the United States in the next few years.[26] Volkswagen, for example, has already opened one plant in Pennsylvania and plans to build a second U.S. plant.[27]

Harbridge House estimated that if a significant induced shift of purchases from imported to domestic automobiles were to occur, 260 businesses (8 percent) would disappear the first year, and an additional 250 businesses would be likely to disappear in subsequent years as the retailing sector in the industry adjusted to new volume levels. This would remove from the American economy businesses with combined assets equal to nearly one-half of those of Lockheed Aircraft.[28]

c. Impact on Consumers

There is a substantial cost to U.S. consumers from the loss of free access to imported motor vehicles. The impact on consumers of tying the fuel efficiency rebate solely to purchases of domestic automobiles meeting fuel efficiency standards can be placed in three categories: a) That relating to reducing the overall choice of automobile characteristics with consequent effect on consumer welfare; b) the effect of limiting the rise in domestic prices of price competitive imports; c) the effect of imports in improving and maintaining competition within the domestic automobile industry. These three categories are, of course, interrelated.

1. *Diversity of Choice.*—A key rationale for foreign trade is that it offers a wider range of choices for U.S. citizens than would otherwise be the case. This is particularly true in the automobile industry. In 1976 four manufacturers held 85 percent of the United States automobile market. More than twenty manufacturers of imports from six countries held the remaining 15 percent. Domestic cars tend to bear strong resemblances to one another in size, styling and engineering. New styling or engineering features either become common to all cars of a particular class very quickly or they are dropped. However, the choices offered by imports are numerous, among which are the following:

Most imports are powered by four-cylinder engines; only one four-cylinder domestic model was available from 1961 to 1970. The~~re are currently six~~ domestic subcompacts offering four-cylinder engines: Chevette, Vega, Monza, Pinto, Bobcat, and Astre.

Tinted glass and rear window defoggers are standard equipment on all but the most basic import models; there are often only optional equipment on comparable American automobiles.

[26] Charles Rivers Study at xvi.
[27] New York Times at D1, D11 (June 15, 1977).
[28] See Harbridge House Study at 12–15, 32.

Imports offer rear-engine placement, transverse front-engine mounting, and mid-engine placement; after 1969 all domestic models were of front-engine design. (Corvair was rear-engine.)

A substantial number of imports offer front-wheel drive; virtually all current domestic models have rear-wheel drive. Front-wheel drive is an important engineering and space-saving feature; yet only 1 percent of all American cars have it.

With the exception of the Chevrolet Corvette, all of the sports cars sold in the American market are imports.

Imports offer a choice among gasoline, diesel, and rotary power plants.

Bucket seats, sunroofs, four-speed and five-speed transmissions, and four-wheel independent suspension were all common items in imports long before they became available as standard or optional items for domestic automobiles.

Van-type station wagons were introduced by Volkswagen but were not duplicated and extensively promoted by domestic manufacturers until the 1970's.

Imports offer the only air-cooled engine.

Should the rebate induce the increased purchase of domestic automobiles by placing imports at a price disadvantage or permit rebates for imported automobiles after negotiating agreements with third countries designed to restrain imports to their "traditional" market share, the size and scope of choices available to consumers desiring a distinct product with a different bundle of utility producing characteristics will be reduced. One of the lessons the U.S. industry has learned is that auto buyers' preferences extend over an extremely wide range and encompass a great variety of qualities. For whatever reason some 15% of buyers prefer foreign cars.

2. *Competitive Effects.*—Consumers benefit from the enhanced competition over product innovation that results from free trade. Foreign car buyers, for example, have benefitted from U.S. technology that developed such characteristics as automatic transmissions, energy-absorbing steering wheels and columns, seal-beamed headlamps, laminated windshields, turn signals. On the other hand, the rotary engine, radial tires, and sun-roofs are examples of innovations that were introduced to American consumers in imported cars.

Furthermore, eliminating or diluting the competition from fuel-efficient imports would remove much of the incentive domestic manufacturers have to improve the fuel economy of their product. Although the Energy, Policy and Conservation Act of 1975 mandates a fleet economy standard of 27.5 mpg by 1985, there are currently twenty-eight imported subcompact models which achieve a mpg greater than that figure. It was only by 1970 that Detroit recognized that the domestic consumer demand for small cars with a high gas mileage was permanent and began to cater to that demand. The first generation of subcompacts appeared in 1970: AMC's Gremlin, Ford's Pinto and GM's Vega. In late 1974–75 the domestic manufacturers began to respond to the appeal of fuel-efficient imports by introducing a second generation of subcompacts with higher gas mileage, such as a modified Pinto with a 34 mpg rating, and the Chevrolet Chevette. It was the competition from Volkswagen, Toyota, Honda, and Datsun that induced General Motors, Chevrolet, and Ford to produce such cars as the Chevette, Maverick, Vega, and Pinto, not government interference in the marketplace.

3. *Impact on Price.*—The landed price of imports acts as a restraint on domestic prices. One econometric study concluded that when the effect of imports on domestic automobile prices is included, the total predicted effect of a 10 percent increase in the import price is a 13.3 percent reduction in the import share and a 3.3225 percent increase in the domestic price.[29] Furthermore, domestic automobile prices decline in response to an increase in the competitiveness of imports.[30] An induced change in domestic prices may reduce by as much as one-third the quantitative impact of import price changes resulting from a tariff or exchange rate on domestic new car sales.[31]

[29] Charles Rivers Assoc. Study, *op. cit.*, at 208.

[30] Imports in terms of supply cost and other costs, are already somewhat at a disadvantage. The supply cost to the U.S. is 8 percent higher for automobiles produced in Japan and about 15 percent higher for West German automobiles than those in the United States. *Id.* at xvi. Furthermore, "[a]ggregating the fuel economy data and price data and correcting for other characteristics, we estimate that foreign subcompacts are approximately 2.33 percent more expensive than domestic subcompacts and foreign compacts, 34.85 percent more expensive." *Id.* at 84.

[31] Charles Rivers Assoc. Study, *op. cit.*, at xv.

The study concluded that foreign and domestic cars are good but not perfect substitutes. The substitution elasticity of demand is —1.33. Thus, "with high substitutability, foreign cars play an important part in constraining the prices of domestic cars."

The denial of a rebate to imported automobiles (save perhaps under executive agreement) acts as a tariff by imposing a premium in the form of the foregone rebate on the purchase of an imported automobile. In terms of the 1978 rebate level, the rebate acts as a percent tariff overall. The average mileage for imports (EPA 1977 estimates) is 33 mpg. Based on the tax and rebate schedules contained in the Committee Print, the 1978–1980 rebates for that mileage are $408, $402 and $393 respectively. Using April 1977 port of entry prices for representative imports, the average price would be $3531.[32] Thus, a denial of a 1978 rebate would effectively be an 11.55 percent tariff; in 1979 an 11.38 percent tariff and in 1980, 11.12 percent. (The figure will probably move downward as average prices rise). Thus in effect a 10–11% tariff would be imposed, and with the reduction in import competitiveness, one can expect domestic prices to rise.

4. *Income Redistribution.*—The Charles Rivers study calculated that in a less than perfect competition situation, an imposition of a tariff in imported cars leads to an income redistribution effect from consumers of new automobiles to factors of production in the domestic automobile. The cost to citizens other than automobile company stockholders, and possibly employees, of an increase in the import tariff is much larger the further the industry structure is from pure competition. A collateral effect of denying a rebate for the purchase of imported automobiles (in effect a 10–11 percent tariff rate) would be some income redistribution.[33]

5. *Net Welfare Loss.*—Finally, the Charles Rivers study concluded that the welfare loss from raising tariff of imposing quotas is higher than the short run gain in increased production due to lower unemployment. The report states:

"Applying standard consumer surplus analysis we find that the welfare gain (loss) on the produce market welfare side from lower (higher) trade barriers exceeds the expected adjustment cost for the high estimate of adjustment costs for most plausible scenarios about the future of the industry and about the regional multiplier effects of increased auto industry unemployment." [34]

The report further states:

"The findings of the report, while confirming that unemployment in the auto industry is an important social problem, suggest that other policy measures, including design of better macroeconomic policies to lessen fluctuations in national output and employment and policies to ease the short-term burden of unemployment and speed up labor market adjustment may be more appropriate than more restrictive trade policies." [35]

Either denying rebates to imported purchasers or permitting rebates on what appears to be a quota basis by executive agreement are such restrictive trade policies.

6. *Discrimination Against Imported Automobiles from the Rebate System Would Result in a Net Domestic Increase in Fuel Consumption.*—The most fuel-efficient automobiles presently in the U.S. market are imports. Of the fifteen highest mileage automobiles (1977 gas mileage) fourteen are imports, with an average combined gas mileage of 39.1 mpg.[36] The only U.S.-manufactured automobile in the top fifteen category was the Chevrolet Chevette. If the proposed discriminatory rebate mechanism were instituted, there would be a substantial net fuel loss to the U.S. economy, resulting from the superior fuel economy of foreign automobiles, which overall, according to EPA statistics, are averaging approximately 33 miles per gallon. Thus, even if a rebate were given for "fuel conserving" domestic automobiles, there would be a net fuel loss to the U.S. economy.

[32] Sources: Automotive News, *op. cit.*, at 77–78. Models of the following manufacturers were selected: Datsun (2 and 4 door sedan), Honda (Civic, Civic CVCC and A-Cord), Fiat (2 door and Custom), Mazda (GLC and Deluxe Hatchback) Subaru (STD, DL and GF Series), Toyota (Corrolla and Corona), Volkswagen (Beetle, Rabbit, Dasher, Scirocco), Volvo (242, 242A, 244, 244A), and the Audi Fox (2 door, 4 door and 100 LS). The higher priced Mercedes-Benz models were not included.

[33] Charles Rivers Study at 56, 338.

[34] The study states that the implicit assumptions used underestimate the present value of the future product welfare loss from tariff increases. Charles Rivers Assoc. Study at 367.

[35] Id. at 7,371. See Chapters 8 and 9.

[36] Source: EPA/FEA 1977 Gas Mileage Guide, Second Edition, January 1977.

A study conducted by Harbridge House, Inc., concluded that the 11.9 million imported cars in use in the United States in 1975 provided an annual savings of 3.2 billion gallons of fuel, or an annual savings of 76 million barrels of gasolione, due to the superior fuel efficiency of these automobiles vis-a-vis their domestic counterparts. In terms of crude oil, 168 million imports were replaced with the same number of domestic automobes.[87]

For the above reasons, and many more, AIADA believes that the rebate proposal, whether applied to both domestic and imported or to solely domestic origin cars, would be an unworkable and potentially economically harmful scheme.

V. THE PROPOSED NATIONAL ENERGY ACT, THE ENERGY POLICY AND CONSERVATION ACT OF 1975, AND THE FUTURE OF AUTOMOBILE IMPORTS

The proposed National Energy Act—in any form—would not "turn the market over" to imported automobiles. As noted above, the impact of the fuel inefficiency tax would be marginal. Moreover, the rebate, if combined with "voluntary" export agreements, would discriminate against imported automobiles.

Of far greater importance than the proposed National Energy Act in determining the share of the market held by imports will be a little-discussed aspect of the Energy Policy and Conservation Act of 1975 related to the "captive" imports of the large U.S. automobile companies. In establishing fleet average fuel economy standards, to become effective in 1978, Congress considered the changeover problems of the domestic automobile industry to the extent of permitting them to include their captive imports in their averaging until 1980. This gave the U.S. manufacturers the opportunity to reach the required fuel economy standards by increasing their imports of fuel-efficient Japanese and European automobiles, at least until 1980, rather than by making immediate and expensive alterations in their existing model mix. This was an opportunity the domestic manufacturers were not slow to seize.

As a consequence of this congressional decision, Ford Motor Company will commence importation of its European-built Fiesta in the Fall of this year. Ford expects to import no less than 300,000 of these small cars in the next two years.

General Motors has transferred the sourcing of its "Opel" import from its wholly-owned German subsidiary to the Izuzu Company in Japan, of which GM owns 34 percent, and can market this fuel-efficient import more aggressively in the coming two years if required to do so to meet fleet average fuel economy standards.

Chrysler has increased imports of its Japanese-built Colt and Arrow models by 253 percent in the first five months of 1977 and can be expected to sell more than 100,000 of these cars for each of the next two years.

But, in 1980, when imports may no longer be included in the fleet averages, but must be calculated separately, there will be a radical change in the automobile market composition. Ford will then begin U.S. production of a new small car based on its successful British Escort model and is expected to cease importation of the Fiesta. At the same time, Ford will replace its imported Capri with a domestically-produced version of the Mustang. General Motors will have a new Chevette, with transverse mounted engine, front wheel drive and other improvements over its present model. It will be available as a four-door sedan and station wagon, in addition to the present two-door, the only model now available. GM also has several other small cars in store for its 1980 customers.

Chrysler will introduce, in 1978, a new small car based on designs from its Simca subsidiary in France, and it can be assumed that its marketing strategy then will be to gradually de-emphasize the successful Colt and Arrow imports.

In 1976, 1,491,910 imported cars were sold in the United States, excluding those from Canada. Of these, 119,358, or eight percent, were captive imports, brought in by GM, Chrysler and Ford. In 1977, imports may rise as high as 1.7 million, of which as many as 214,000 may be captive imports sold by Detroit's big three, or 12½ percent of the import market.

In 1978, assuming that Ford imports 150,000 Fiesta models, that GM increases its Opel imports to 50,000 units and that Chrysler's Colt and Arrow imports stay at 150,000 units, captive imports could reach from 350,000 to 400,000 units.

Meanwhile, the total imported car market will be affected by the switch of Volkswagen Rabbit production from Germany to the United States. This would approximately offset the importation of Fiesta's by Ford. This provides the basis for a forecast of 1.8 million imports sold in 1978, of which 400,000 or 22 percent will be captives from GM, Ford and Chrysler.

[87] Harbridge House Study at 48.

Imports could easily reach two million in 1979 and then drop back to an almost traditional 1.5 million units in 1980 when the fleet fuel economy averages force domestic manufacturers to cease their international juggling of production and manufacture cars that meet the fleet averages solely in the United States.

Our studies show no comparable impact on market shares exerted by any proposed rebates and/or gas-guzzler taxes, or any combination of the two.

Mr. Chairman, this concludes my testimony. I would be glad to attempt to answer any questions that you may have.

APPENDIX I.—COMPARISON OF FUEL ECONOMY CHANGES AMONG AUTO COMPANIES, 1975-77

	Sales-weighted		Miles per gallon changes 1975-76 (percent)	1977 (sales-weighted miles per gallon)	System optimization only [1]	New engine/vehicle combinations only	Weight mix shifts	All changes combined
	1975	1976						
American Motors	19.0	18.3	−3.7	19.2	−0.6	+2.6	+2.8	+4.8
Chrysler	15.5	16.5	+6.4	16.6	+3.3	−.1	−2.7	+.5
Ford	13.6	17.3	+27.2	17.1	+2.1	−1.0	−2.5	−1.4
General Motors	15.4	16.7	+8.4	18.4	+3.2	+.7	+6.5	+10.4
BMW	17.7	18.9	+6.8	20.4	+2.8	0	+5.3	+8.0
Nissan	24.9	26.9	+8.0	27.1	+.6	−1.1	+1.2	+.7
Porsche	19.8	20.5	+3.5	19.8	−8.8	−3.8	+9.2	−3.4
Toyo Kogyo	16.7	21.9	+31.1	26.1	+8.5	−1.1	+11.8	+19.2
Toyota	22.2	25.0	+12.6	28.1	+4.8	+1.6	+6.0	+12.3
VW	27.4	28.3	+3.3	30.4	+4.5	+.3	+2.5	+7.3
Volvo	19.2	19.4	+1.0	19.9	+1.6	0	+1.4	+2.9
Audi	24.2	25.2	+4.1	25.9	−2.7	0	+5.6	+3.0
Fuji	26.5	29.7	+12.1	30.2	+8.4	−7.3	+.3	+1.5
Fleet average	15.6	17.6	+12.8	18.6	+2.8	+.2	+2.6	+5.6

[1] No new technology or components, but improved combinations of existing equipment and methods.

Source: Staff of the Joint Committee on Taxation, 95th Cong., 1st sess., Report on the Energy Tax Proposals Relating to Transportation at 11 (committee print, 1977).

APPENDIX II.—DOMESTIC AUTOMOBILES ELIGIBLE FOR A 1978 AND 1979 REBATE [1]

[Based on EPA 1977 gas mileage]

Manufacturer/model and engine size	Transmission	Combined MPG
SUBCOMPACT CARS		
American Motors:		
Gremlin:		
121/4	M	25
121/4	A	24
232/6	M	23
232/6 [2]	A	20
258/6	M	20
Buick:		
Skyhawk:		
231/6	M	21
231/6	A	21
Chevrolet:		
Camaro: 250/6	M	20
Chevette:		
85/4	M	33
85/4	A	29
98/4	M	36
98/4	A	30
Monza:		
140/4	M	28
140/4	A	24
305/8	A	20
Vega:		
140/4	M	28
140/4	A	24
Ford:		
Maverick: 200/6	M	24
Mustang II:		
140(2.3L)/4	M	26
140(2.3L)/4	A	24
171(2.8L)/6	M	23
Pinto:		
140(2.3L)/4	M	30
140(2.3L)/4	A	26
171(2.8L)/6	A	20

See footnotes at end of table.

APPENDIX II.—DOMESTIC AUTOMOBILES ELIGIBLE FOR A 1978 AND 1979 REBATE[1]—Continued

[Based on EPA 1977 gas mileage]

Manufacturer/model and engine size	Transmission	Combined MPG
Lincoln-Mercury:		
Bobcat:		
140(2.3L)/4	M	30
140(2.3L)/4	A	26
171(2.3L)/6	A	20
Comet:		
200/6	M	24
200/6	A	20
250/6	M	24
Oldsmobile:		
Starfire:		
140/4	M	28
140/4	A	24
231/6	M	21
231/6	A	21
305/8	A	20
Plymouth Cricket: 98/4[2]	M	33
Pontiac:		
Astre:		
140/4	M	28
140/4	A	24
151/4	M	30
151/4	A	27
Firebird: 231/6	A	20
Sunbird:		
151/4	M	30
151/4	A	27
231/6	M	21
231/6	A	21
COMPACT CARS		
American Motors:		
Hornet:		
232/6	M	20
232/6	A	20
Pacer:		
232/6	M	20
232/6	A	20
Buick Skylark: 231/6	A	20
Chevrolet:		
Nova:		
250/6	M	22
250/6	A	20
Dodge:		
Aspen:		
225/6	M	23
225/6	A	20
225/6	M	20
Ford:		
Granada:		
200/6	M	24
250/6	M	24
250	A	20
Lincoln Mercury:		
Monarch:		
200/6	M	24
250/6	M	24
250/6	A	20
Oldsmobile:		
Omega:		
231/6	M	20
231/6	A	21
Plymouth:		
Volare:		
225/6	M	23
225/6	A	20
225/6	M	20
Pontiac:		
Ventura/Phoenix:		
151/4	M	26
151/4	A	24
231/6	M	20
231/6	A	21
MID SIZE CARS		
Buick Century/Regal: 231/6	A	20
Chevrolet Malibu: 250/6	M	20

See footnotes at end of table.

APPENDIX II.—DOMESTIC AUTOMOBILES ELIGIBLE FOR A 1978 AND 1979 REBATE[1]—Continued
[Based on EPA 1977 gas mileage]

Manufacturer/model and engine size	Transmission	Combined MPG
Oldsmobile:		
Cutlass:		
231/6	A	20
260/8	M	29
Pontiac Le Mans: 231/6	A	20
LARGE CARS		
Buick Le Sabre: 231/6	A	20
Oldsmobile Delta 88: 231/6	A	20
Pontiac: 231/6	A	20
SMALL STATION WAGONS[2]		
American Motors:		
Hornet wagon:		
232/6	M	20
232/6	A	20
Pacer wagon:		
232/6	M	20
232/6	A	20
Chevrolet:		
Vega wagon:		
140/4	M	28
140/4	A	24
Ford:		
Pinto wagon:		
140 (2.3L)/4	M	26
140 (2.3L)/4	A	24
171 (2.8L)/6	A	20
Lincoln Mercury:		
Bobcat wagon:		
140 (2.3L)/4	M	26
140 (2.3L)/4	A	24
171 (2.8L)/6	A	20
Pontiac:		
Astre Safari wagon:		
151/4	M	30
151/4	A	27
MIDSIZE STATION WAGONS[3]		
Dodge Aspen wagon: 225/6	M	20
Plymouth Volare wagon: 225/6	M	20

[1] Using the ITC Master Sheet Set of Assumptions for the Auto/Energy Study.
[2] Not equipped with catalyst.
[3] Eligible for a 1978–79 rebate based on EPA 1977 mileage estimates.

APPENDIX III.—1976 CALENDAR YEAR PRODUCTION OF U.S. CARS BY SIZE CLASSIFICATION

U.S. model small cars	Units	Percent of U.S. total production	EPA combined MPG	1978 rebate?
Subcompacts:				
Mustang II	183,369	2.15	26.0	X
Chevette	154,910	1.81	32.0	X
Vega	136,283	1.60	28.0	X
Pinto	108,140	1.27	30.0	X
Astre	43,102	.50	27.25	X
Gremlin	39,055	.46	21.57	X
Bobcat	39,063	.46	25.33	X
Monza	21,059	.25	22.5	X
Sunbird	17,077	.20	24.75	X
Skylark	528,599	1.51	21.0	X
Starfire	8,391	.10	22.0	X
Total	879,054	[1] 10.31		

APPENDIX III.—1976 CALENDAR YEAR PRODUCTION OF U.S. CARS BY SIZE CLASSIFICATION

U.S. model small cars	Units	Percent of U.S. total production	EPA combined MPG	1978 rebate?
Compacts:				
Volare	311,259		18.25	
Granada	415,421	4.86	20.0	X
Nova	312,379		18.5	
Aspen	232,742		18.25	
Camaro	201,652		18.0	
Monarch	133,700	1.56	20.0	
Skylark	126,599		17.66	
Firebird	125,019		18.0	
Maverick	92,378	1.08	21.2	
Ventura	86,750	1.02	20.8	X
Pacer	72,698	.85	19.4	X
Omega	67,120	.79	19.4	X
Hornet	61,842		18.8	X
Sportsman	50,946			
Valiant	35,696			
Club Wagon	35,007			
Comet	31,510	.38	21.2	X
Sportvan	27,203			
Dart	26,960			
Voyager	14,968			
Total	1,197,656	[1] 10.54		
Intermediates:				
Cutlass	560,065		18.8	
Chevelle	371,617			
Monte Carlo	364,177		16.5	
Century	345,201		18.0	
Grand Prix	271,275		17.6	
LTD II/Torino	198,332		16.0	
Cougar/Montego	139,061		16.0	
Fury	114,265		15.6	
T-Bird/Elite	212,951			
Le Mans	89,713		18.4	
Monaco	77,656		15.6	
Matador	38,332		15.3	
Total	2,782,545			
Standards:				
Chevrolet	370,885		18.0	
Buick	309,099			
Oldsmobile	295,759		18.0	
Ford	248,549		15.0	
Pontiac	151,695		18.4	
Chrysler	127,466		13.0	
Mercury	91,509		14.0	
Plymouth	57,466			
Dodge	49,845			
Toronado	33,095		15.0	
Riviera	22,940		17.5	
Total				
Luxury standards:				
Cadillac	233,575		15.0	
Lincoln	64,584		14.0	
Mark IV	60,296			
Eldorado	39,995		13.5	
Total	398,450			
United States 1976 production	8,543,363			

[1] Percent of total production: 10.31.
[2] Percent of total production: 5.68.

Note: Percent of total 1976 production which would have been eligible for a rebate: 20.85.
Sources: EPA 1977 Estimated Gas Mileage, Ward's Automotive Reports (Feb. 14, 1977).

APPENDIX IV.—JOBS IN THE MOTOR VEHICLE AND EQUIPMENT INDUSTRY PER INCREMENTAL AUTOMOBILE PRODUCED

	Unit production increment over previous year—in millions	Increase in new car related jobs—in thousands	Jobs per incremental unit produced
Year:			
1962	1.41	45.4	0.032
1963	.70	27.1	.039
1965	1.55	66.2	.043
1968	1.39	33.3	.024
1971	2.04	50.0	.025
1973	.83	38.7	.047

Note: Average for years 1962–73: 0.035 incremental jobs per incremental unit produced.

APPENDIX V.—DEALERSHIP EMPLOYMENT ASSOCIATED WITH DOMESTIC AUTOMOBILES AND CAPTIVE IMPORTS 1969–75

	Total employment	Domestic cars registered—in thousands	Captive imports registered—in thousands	Total—in thousands
Year:				
1969	686,400	8,379.1	114.0	8,493.1
1970	665,000	7,152.8	112.2	7,265.0
1971	631,200	8,258.8	203.4	8,462.2
1972	656,000	8,400.8	187.1	8,587.9
1973	666,800	9,625.1	217.0	9,842.1
1974	638,300	7,326.7	177.5	7,504.2
1975	602,000	6,757.5	154.7	6,912.2

[1] Total employment figures were derived by taking the totals published by NADA for employees of all franchised new car dealerships and subtracting those calculated by Harbridge House as attributable to noncaptive imports.

Sources: NADA, "The Franchised New Car and Truck Dealer Story: 1976 Edition;" Harbridge House Research; Automotive News Almanac, 1973 and 1976 editions.

Senator HATHAWAY. Our next witness is Mr. J. K. Aldous, managing director, public and government policy, American Automobile Association. He is accompanied by Mr. Jerry C. Connors, director, Legislative Affairs Department, American Automobile Association, and Mr. William R. Berman, manager, Environment and Energy Department, American Automobile Association.

We are on a 10-minute limitation. We will put your entire statement in the record. If you could summarize it, we would appreciate it.

STATEMENT OF J. K. ALDOUS, MANAGING DIRECTOR, PUBLIC AND GOVERNMENT POLICY, AMERICAN AUTOMOBILE ASSOCIATION, ACCOMPANIED BY JERRY C. CONNORS, DIRECTOR, LEGISLATIVE AFFAIRS DEPARTMENT, AMERICAN AUTOMOBILE ASSOCIATION, AND WILLIAM R. BERMAN, MANAGER, ENVIRONMENT AND ENERGY DEPARTMENT, AMERICAN AUTOMOBILE ASSOCIATION

Mr. ALDOUS. Thank you, Mr. Chairman.

We appreciate the opportunity to appear before this committee. The American Automobile Association has more than 900 affiliated clubs and branches serving automotive and travel needs of almost 19 million members. We commend the administration and the Congress for coming to grips with a national energy plan.

We still believe that more of a free-market approach—with proper incentives, safeguards, and competition—one which has served the country well, is the best approach to working our way out of the energy problem.

Most of all, we feel that proposed solutions should deal directly with matters of energy supply, use, and conservation. They should not attempt to solve other problems, such as budget deficits, however legitimate those problems may be.

With that philosophy in mind, we respectfully disagree with certain approaches advocated by the administration and acted upon by the House of Representatives in time for summer adjournment.

We know, as do you and others in authority, why our energy problems are serious.

U.S. oil production has declined since 1970 and our proven reserves are being used up faster than new supplies are being found. We rely on foreign oil more now than we did at the time of the oil embargo almost 4 years ago.

But despite the dangers inherent in such heavy and rising reliance on foreign suppliers, it seems that the public views the energy problem largely as one of rising consumer costs.

Indeed, costs are rising. The pump price of gasoline has risen at least 60 percent in the past 4 years.

Because of this, we doubt that the public is willing to embrace certain aspects of the administration's energy plan. A recent analysis by the Heritage Foundation termed it "the most significant increase in the middle-class American's tax burden in our Nation's history." The foundation said that the plan would cost the public $337 billion over the next 8 years.

And the Consumer Federation of America says that Mr. Carter's plan could raise energy prices 74 percent in the next several years.

These prospects require careful attention by this committee for the counterproductive effect they would have on the Nation's economy, particularly tourism.

Fortunately, the House Ways and Means Committee rejected the administration's 50-cents-a-gallon standby gasoline tax last month and, last week, the entire House resoundingly defeated two other gas tax proposals.

Nevertheless, there are still alive three other proposals that, if approved, would force an unnecessary financial burden on the motorist. I say unnecessary, because the proposals would not help solve energy problems.

The first is the proposed tax on so-called gas guzzling automobiles. We do not need this tax because the Government has already established levels of fuel economy for the automakers to meet. The levels can be met.

They will achieve significant fuel savings in line with national goals and, equally important, will preserve a great deal of freedom of choice for auto buyers, whose individual needs in personal mobility vary greatly.

The second proposal is to eliminate the Federal income tax deduction for State gasoline taxes. We oppose this and wonder why it is even considered in an energy package.

Structured the way it is, this tax deduction elimination would have little effect on consumption. Revenues would merely help pay off the Federal debt.

Third, and of greater concern, is the crude oil equalization tax. For the motorist, this wellhead tax could amount to about 7 cents a gallon more at the gas pump and, as planned by the House, would return most of the proceeds to the public—partly to subsidize home heating oil users—during its initial year.

It will not reduce consumption because with gasoline prices having jumped 60 percent in 4 years, the American need to travel by automobile has not diminished.

The crude oil tax is a revenue raiser, plain and simple. We consider it to be an unwarranted, unjust measure.

Why make the car owner in Nevada pay for home heating bills in New England?

Not addressed in these proposals is the fact that the Carter administration, through the Federal Energy Administration, hopes to decontrol gasoline prices at the retail level when the heavy summer driving period ends. This assures a price rise of some sort, but does not assure adequate distribution of supplies.

As an alternative to the three unwise tax proposals, AAA suggests that Congress take positive steps to bring about more efficient use of our resources.

Specifically, this committee could work to enhance the development of oil from shale, shift additional stationary energy users from petroleum to other fuels, increase availability of fuel extenders for gasoline and underscore the economies of carpooling, vanpooling, and charter buses for commuting.

We commend Senator Floyd Haskell of this committee who seeks to make productive an estimated 600 billion barrels of oil locked in high- and medium-grade shale in the United States, mainly on Federal land. Senator Haskell has introduced S. 419 to test various shale oil technologies.

Next to coal, shale oil is our largest fossil fuel resource, but the Government has been cool toward its development.

We would like to know why, and we urge members of this committee to support Senator Haskell's bill. Moreover, this committee should create the appropriate Federal incentives for the financing of shale oil projects.

In considering alternate sources, there is an urgent need to relieve the strain on petroleum demand by shifting more heavy industrial, utility, and other stationary energy users of coal, nuclear, and other fuels.

Such alternatives are simply out of technological reach in the near term for mobile energy users. Because most of the Nation's transportation system—the lifeblood of our economic structure—involves motor vehicles, the priorities in adapting to petroleum alternatives are obvious.

Along these same lines, this committee should take a serious look at the way the United States can use alcohol to stretch the gasoline we consume. Gasoline-alcohol blends, especially a 90–10 blend that requires no engine readjustment, has been around for years.

The number even coincides with the 10-percent reduction in oil use sought by the administration by 1985. The Energy Research and Development Administration considers "gasohol" the best near-term prospect for reducing petroleum demand.

This is another area where this committee can suggest appropriate incentives. Yesterday's front page news told of administration plans to idle millions of acres of farm land to combat grain surpluses. Why should farmers be paid for not growing grain when it could be processed into alcohol to extend gasoline supplies?

Finally, this committee and the rest of the Federal Government should do all it can to promote the use of vanpooling, carpooling, and charter buses where practical—as we have—by individuals, communities, and large companies.

The economics of ride-sharing are so well known that I will not dwell on them. The question for today is not what ride-sharing can do, but how to go about accomplishing this substantial energy-savings measure.

Our energy problems will not be solved overnight, but we feel that with your help, these steps will get us going in the right direction.

This concludes by remarks. I will be happy to answer any questions you might have.

The CHAIRMAN. Thank you very much.

Senator Packwood?

Senator PACKWOOD. No questions.

Senator HATHAWAY. I was intrigued by the statement you made at the beginning that you thought a free-market approach would be better. Would you explain that a little more? How has the free market helped with respect to conservation?

Mr. ALDOUS. Well, sir, I think that I said free market with some safeguards. As has been indicated in testimony here, and certainly in the House of Representatives, a free market means allowing the oil industry and others to let fuel prices rise to world levels, but not as the Carter administration is attempting to do in a controlled process plus taxes. If we (the United States) mean what we say, that we are not placing the proper value on our domestic oil resources, then if those prices are allowed to rise to world levels—with adequate safeguards, with controls through some mechanism within the purview of this committee so that excess profits are returned directly into further exploration and development of alternate fuels—that sort of an approach would be much more beneficial for reducing reliance on foreign oil and much less disruptive to the economy and would certainly not require the tremendous amount of deliberation that is going on now in simply trying to shift taxes from one pocket to another.

Senator HATHAWAY. Will that not be quite onerous on those low-income people who need to use their automobiles?

Mr. ALDOUS. All of those taxes are going to be onerous, too, sir. We also have other programs to take care of those problems. I think that we have just seen, in the past few days, the announcement of an entirely new approach to a welfare program, which will cost another $6 billion. With that in mind, there are ways that this committee could assure that those low-income people could be taken care of.

Senator HATHAWAY. Thank you.

The CHAIRMAN. Senator Matsunaga?

Senator MATSUNAGA. Thank you, Mr. Chairman.

Your suggestion of various alternatives to the President's program is interesting. I am especially interested in your suggestion that we—when I say we, I mean the Government—promote the use of a 90 to 10 blend of gasoline and alcohol. Is this very much in use now? If so, where?

Mr. ALDOUS. It is not very much in use now. It has been around for some time. It was used clear back in World War II.

There are ways of developing it. There are a few demonstration projects going on. There is an active program in Nebraska.

We think that there is very definitely every reason to expect that the potential for using this 90 to 10 blend, or something similar is great, in certain regions of the country.

Senator MATSUNAGA. Do you happen to have any figures as to what alcohol would cost?

Mr. ALDOUS. I could supply those figures. We can supply them. It would be a few cents more per gallon, perhaps, than gasoline.

[The following was subsequently supplied for the record:]

AUGUST 15, 1977.

Hon. SPARK M. MATSUNAGA,
U.S. Senate,
Russell Senate Office Building,
Washington, D.C.

DEAR SENATOR MATSUNAGA: Complying with your request for information regarding the cost of alcohol production, I cite the following reference from *Methanol: Its Synthesis, Use as a Fuel, Economics, and Hazards*, published in December 1976 by the Energy Research and Development Administration:

". . . the costs of methanol vary widely depending on the type and cost of feedstocks as well as type of synthesis used. Methanol production costs from coal may soon become competitive with those from natural gas as natural gas prices continue to rise. Numerous synthetic methods using renewable resources may soon become competitive also, especially where the prices of petroleum fuels are very high. Similar considerations apply to other synthetic fuels.

In the long run methanol may be less expensive than other synthetic fuels when overall energetic and life cycle costs are included for the entire system. Detailed analyses using identical assumptions will be necessary to make accurate comparisons. The costs of converting existing fossil fuel systems to methanol are small compared to the lifecycle benefits of increased efficiency, reduced pollution and lower costs."

In addition, I quote Dr. William A. Scheller, a leading authority on "Gasohol", who recently told Nebraska legislators that, based on refinery prices for gasoline last November, "Gasohol" (a blend of *ethanol* and gasoline) could have been retailed in Lincoln for 63.9 cents a gallon. That, said Scheller, was the same as the then median price of five major brands of no-lead gas on sale in the state capitol. He broke down costs this way: Gasoline, 30.8 cents; ethanol, 11 cents; transportation, 3.3 cents, filling station mark-up for overhead and profit, 9.3 cents; state tax, 5.5 cents, federal tax, 4 cents.

Sincerely,

J. KAY ALDOUS,
Managing Director,
Public and Government Policy.

Senator MATSUNAGA. It would be more expensive than gasoline?

Mr. ALDOUS. It would be at this point, yes, sir.

The CHAIRMAN. But you could make it out of sugar cane.

Senator MATSUNAGA. I think that is an area that we should really take a good look at. As a matter of fact, we did provide, in the ERDA budget, I believe, $100 million to conduct research in this area.

Mr. ALDOUS. We think that research is important, but we think it is time for demonstration projects to be funded in in any of these areas.

Senator MATSUNAGA. Coming to your suggestion that we increase the development of shale oil. I do not know whether you were here the first day when we were questioning the Secretary of Energy, Dr. Schlesinger, but the chairman is one of the real frontrunners in the effort—I should say forefighters—for the development of shale, and I agree with you heartily that we ought to go into the development of shale oil, and we were told that there is a supply that would last for 200 years.

Mr. ALDOUS. There is a least one petroleum company that is actively involved in it now. We believe that the Energy Research and Development Administration may be coming along with a demonstration project which essentially will only reinvent the wheel in this respect. Maybe there are two such companies that are in it actively and should be producing more than the ERDA demonstration project will be attempting.

Senator MATSUNAGA. I have no further questions.

The CHAIRMAN. One could take sugar cane in Hawaii and make alcohol out of it, take what remains of the stalk, burn that and make electricity and tap the hot rock in those volcanos out there in Hawaii, and you could be exporting energy and supplying all of our needs.

Everything we can do to produce more energy and make better use of it, we should do.

Do you agree with some of our friends who feel that the way to solve this whole energy crisis is just to do without, and cut back on our lifestyle?

Mr. ALDOUS. No, sir. I believe it does not have to be done. I think there are those who would say that we are extravagant in the way we live, but without considering the fact that our standard of living in general is certainly the highest in the world; because we use more energy does not necessarily mean that we are more wasteful. We also have proportionately more total gross national product than other nations.

The CHAIRMAN. Thank you very much.

[The prepared statement of Mr. Aldous follows:]

STATEMENT OF J. KAY ALDOUS, MANAGING DIRECTOR, PUBLIC AND GOVERNMENT POLICY, AMERICAN AUTOMOBILE ASSOCIATION

Mr. Chairman, members of the committee, I am J. Kay Aldous, managing director of public and government policy for the American Automobile Association. With me from AAA are Jerry C. Connors, director of legislative affairs, and William R. Berman, manager of energy and environment.

AAA has more than 900 affiliated clubs and branches serving automotive and travel needs of almost 19 million members. We're pleased to have the opportunity to discuss energy with this committee, and we applaud efforts by the Administration and Congress to come to grips with a national energy plan.

We still believe that more of a free-market approach—with proper incentives, safeguards and competition—one which has served the country well, is the best approach to working our way out of the energy problem.

Most of all, we feel that proposed solutions should deal directly with matters of energy supply, use and conservation. They should not attempt to solve other problems, such as budget deficits, however legitimate those problems may be.

With that philosophy in mind, we respectfully disagree with certain approaches advocated by the Administration and acted upon by the House of Representatives in time for summer adjournment.

We know, as do you and others in authority, why our energy problems are serious.

U.S. oil production has declined since 1970[1] and our proven reserves are being used up faster than new supplies are being found. We rely on foreign oil more now than we did at the time of the oil embargo almost four years ago.[2]

But despite the dangers inherent in such heavy and rising reliance on foreign suppliers, it seems that the public views the energy problem largely as one of rising consumer costs.

Indeed, costs are rising. The pump price of gasoline has risen at least 60 percent in the past four years.

Because of this, we doubt that the public is willing to embrace certain aspects of the Administration's energy plan. A recent analysis by the Heritage Foundation termed it "the most significant increase in the middle-class American tax burden in our nation's history." The foundation said that the plan would cost the public $337 billion over the next eight years.

And the Consumer Federation of America says that Mr. Carter's plan could raise energy prices 74 percent in the next several years.[3]

These prospects require careful attention by this committee for the counterproductive effect they would have on the nation's economy, particularly tourism.[4]

Fortunately, the House Ways and Means Committee rejected the Administration's 50-cents-a-gallon standby gasoline tax last month and, last week, the entire House resoundingly defeated two other gas tax proposals.[5]

Nevertheless, there are still alive three other proposals that, if approved, would force an unnecessary financial burden on the motorist. I say unnecessary because the proposals wouldn't help solve energy problems.

The first is the proposed tax on so-called gas guzzling automobiles. We don't need this tax because the government has already established levels of fuel economy for the auto makers to meet. The levels can be met.[6] They will achieve significant fuel savings in line with national goals and, equally important, will preserve a great deal of freedom of choice for auto buyers, whose individual needs in personal mobility vary greatly.

The second proposal is to eliminate the federal income tax deduction for state gasoline taxes. We oppose this and wonder why it's even considered in an energy package. Structured the way it is, this tax deduction elimination would have little effect on consumption. Revenues[7] would merely help pay off the federal debt.

Third, and of greater concern, is the crude oil equalization tax. For the motorist, this wellhead tax could amount to about seven cents a gallon more at the gas pump and, as planned by the House, would return most of the proceeds to the public—partly to subsidize home heating oil users[8]—during its initial year. It won't reduce consumption because with gasoline prices having jumped 60 percent in four years, the American need to travel by automobile has not diminished.

The crude oil tax is a revenue raiser, plain and simple. We consider it to be an unwarranted, unjust measure. Why make the car owner in Nevada pay for home heating bills in New England?

Not addressed in these proposals is the fact that the Carter Administration, through the Federal Energy Administration, hopes to decontrol gasoline prices at the retail level when the heavy summer driving period ends. This assures a price rise of some sort, but does not assure adequate distribution of supplies.

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[1] Domestic crude oil production peaked at 9.6 million barrels of oil a day (b/d) in 1970 and had declined to 8.1 million b/d as of 1976. Source: Bureau of Mines.

[2] U.S. has become dependent on foreign sources for more than 45 percent of the oil it uses. Imports from the Mid-East alone, increased more than 61 percent in the past year. Source: American Petroleum Institute.

[3] The Consumer Federation of America citing a Congressional Budget Office staff working paper entitled, "President Carter's Energy Proposals: A Perspective," dated June, 1977.

[4] Tourism is vital to every state's economic well-being. In 3 states—Florida, Hawaii and Nevada—tourism is the leading industry. In 6 others—California, Texas, Pennsylvania, Illinois, Michigan and Ohio—tourism brings in more than $1 billion annually. In 3 other states—Maine, Alaska and Arizona— dependence on the tourism dollar is extremely heavy. Source: Discover America Travel Organizations.

[5] The House defeated a 4-cent gasoline tax by a 4 to 1 margin and a 5-cent tax by a 7 to 1 margin on August 4, 1977.

[6] The U.S. Department of Transportation declared in July 1977 that the auto industry could meet—and possibly exceed—statutory fuel economy standards. Source: DOT News Release.

[7] Total federal revenue derived from eliminating the deduction for state gasoline taxes would be $700 million. Source: U.S. Treasury Dept.

[8] Rebates from the crude oil equalization tax—as approved by the House—initially would have amounted to $25 per person. However, the House had that amount reduced to $22 per person in order to pay for an additional rebate to residential users of home heating oil. Source: House Ways and Means Committee Report on H.R. 6831, July 19, 1977.

As an alternative to the three unwise tax proposals, AAA suggests that Congress take positive steps to bring about more efficient use of our resources.

Specifically, this committee could work to enhance the development of oil from shale, shift additional stationary energy users from petroleum to other fuels, increase availability of fuel extenders for gasoline and underscore the economies of carpooling, vanpooling and charter buses for commuting.

We commend Sen. Floyd Haskell of this committee who seeks to make productive an estimated 600 billion barrels of oil locked in high- and medium-grade shale in the U.S., mainly on federal land. Senator Haskell has introduced S-419 to test various shale oil technologies. Next to coal, shale oil is our largest fossil fuel resource, but the government has been cool towards its development. We'd like to know why, and we urge members of this committee to support Senator Haskell's bill. Moreover, this committee should create the appropriate federal incentives for the financing of shale oil projects.

In considering alternate sources, there is an urgent need to relieve the strain on petroleum demand by shifting more heavy industrial, utility and other stationary energy users to coal, nuclear and other fuels. Such alternatives are simply out of technological reach in the near term for mobile energy users. Because most of the nation's transportation system—the life-blood of our economic structure—involves motor vehicles, the priorities in adapting to petroleum alternatives are obvious.

Along these same lines, this committee should take a serious look at the way the U.S. can use alcohol to stretch the gasoline we consume. Gasoline-alcohol blends, especially a 90–10 blend that requires no engine readjustment,[9] have been around for years. The number even coincides with the 10 percent reduction in oil use sought by the Administration by 1985. The Energy Research and Development Administration considers "gasohol" the best near-term prospect for reducing petroleum demand. This is another area where this committee can suggest appropriate incentives. Why should farmers be paid for not growing grain when it could be processed into alcohol to extend gasoline supplies?

Finally, this committee and the rest of the federal government should do all it can to promote the use of vanpooling, carpooling and charter buses where practical—as we have—by individuals, communities and large companies. The economics of ride-sharing are so well known that I won't dwell on them.[10] The question for today is not what ride-sharing can do, but how to go about accomplishing this substantial energy-savings measure.

Our energy problems won't be solved overnight, but we feel that with your help these steps will get us going in the right direction.

This concludes my remarks. I'll be happy to answer any questions you might have.

The CHAIRMAN. Next, we will call Mr. Marvin L. Glassman, president, International Taxicab Association, accompanied by Mr. Joseph Curry, independent driver-owner.

We are pleased to have you.

STATEMENT OF MARVIN L. GLASSMAN, PRESIDENT, INTERNATIONAL TAXICAB ASSOCIATION

Mr. GLASSMAN. Mr. Chairman, members of the committee, I regret that Mr. Curry, for personal reasons, could not be here, but his testimony will be presented for the record.

My name is Marvin Glassman. I am president of the International Taxicab Association located in Rockville, Md. On my left is Richard Gallagher, executive vice president of the association.

The International Taxicab Association is an organization of over 900 fleet operators and local associations in the United States and Canada operating over 3,000 corporations. It is a not-for-profit orga-

[9] Spokesmen for General Motors, Ford and Chrysler reportedly maintain that a 10 percent mixture of alcohol in gasoline will not require engine adjustments. Source: Detroit News, Dec. 15, 1976.

[10] Increasing passenger-to-auto ratios from the present 1.2 persons per car to 1.6 persons would save 400,000 barrels of the nearly seven million barrels of gasoline the U.S. consumes daily. Source: Federal Energy Administration.

nization established in 1917 for the purpose of providing the dissemination of economic and statistical information to the taxicab industry through conventions, meetings, and publications.

I am a second generation taxicab operator in Columbus, Ohio. My entire business career has been in transportation.

I appear before you today because our industry has operated under an inequitable law, and further tax revisions will compound that inequity. The Internal Revenue Code of 1954 granted a rebate to local transit systems with capital grants and supporting services.

Many State legislatures have also extended special tax relief and funding to local transit systems. Proposed legislation under the Energy Tax Act of 1977 provides for the extending of that exemption to "intercity bus, local, and school bus."

I recognize the economic conditions that require relief from this tax. However, this industry has the same common problems and, in many instances, compete directly for business with these systems.

The taxicab industry will be forced to subsidize additional competition through taxes. I have 15 quotations from various consultants, economists, and government studies describing the role taxicab's play in public passenger transportation in exhibit B, which is part of this statement.

Surveys of the taxicab industry indicate that over 60 percent of the trips are by housewives, students, unemployed, elderly, or handicapped persons.

I would like to briefly cite some findings from exhibit A.

In the year 1975, the taxicab industry transported 3.4 billion passengers as compared to 5.6 billion for transit.

The taxicab industry had 5,387 companies as compared to 947 transit authorities and companies and 950 intercity bus companies.

The taxicab industry has over one-half million workers as compared with 200,000 for transit and 46,000 for intercity bus. Therefore, the taxicab industry exceeds all other forms of public passenger transportation.

The taxicab industry is comprised of small businesses; the average company fleet is 55 vehicles and over 1,300 companies have less than 10 vehicles.

The cost-effectiveness and the diversity of taxicabs are clearly recognized. To further elaborate on the diversification of taxicab companies, my own company transports 1,400 exceptional children (the physically handicapped, neurologically handicapped, the blind, the deaf, the hyperactive, and the educatable mentally retarded). 80 to 90 percent of our total business is by telephone order and we dispatch from 3,000 to 6,000 orders every 24 hours.

The company has a wide variety of services and markets, such as: employees of local business firms, government employees, school children, senior citizens, blind and partially sighted, on-the-job injuries and emergencies, dialysis patients, insurance claim patients, telephone messages, patients in prepaid medical plans, wheelchair patients, hospital patients, welfare recipients, blood delivery, medical lab and X-ray delivery, package delivery, telegrams.

It would appear from my remarks that the taxicab industry is aggressively servicing existing and new markets and therefore should be a profitable industry. Unfortunately, the industry has not been able to keep pace with inflation, particularly in the areas of insurance and fuel.

The taxicab industry has had its fuel costs increase from approximately 6 to 12 percent of the total operating costs. A similar increase has occurred in insurance costs in 3 years.

In this year alone, we have seen an additional increase in the cost of gasoline of approximately 4½ cents nationwide.

A study by Control Data Corp, and Wells Research Co., Taxicab Operating Characteristics, dated March 1977, pages S-4, states:

> Taxicab fleet operators have evidently experienced profit declines from 1970 to 1975. In 1975, the revenues of nearly 50 percent of the companies did not cover total costs—including capital costs. Revenues of 25 percent of the companies did not cover out of pocket costs. This tends to verify observed conditions in the industry resulting from drastic increases in fuel, insurance and labor costs.

Simply stated, this means 25 percent of the companies will not be able to remain in business.

In a 1974 survey, there were 6,467 taxicab operators and the 1975 survey listed 5,387. Some went bankrupt; others merged; many of the small companies simply closed their doors.

Our industry is oriented toward delivering local services and this may explain why we have been receiving support and commendations from local and State authorities. Within the last several years the States of Virginia, Michigan, and Wisconsin have given the industry a full rebate on State gasoline taxes. A number of other States are contemplating such actions.

In each case, substantial testimony and documentation of the industry's conditions have led to the conclusion that taxicabs should not have tax relief, but must be put on a par with other forms of transportation.

In cases where the taxicab industry has had the opportunity to bid on services for the elderly and handicapped, it has consistently been a low bidder in spite of subsidized competition.

For too long we have been identified with expense account riders and exclusive use taxicabs. This is not true. In many cities, Washington, D.C., included, there are now shared ride services which, when used efficiently, can be as cost-effective and energy conservative as any form of public passenger transportation.

Gasoline is the raw material upon which the taxicab industry operates. If the industry can stimulate shared riding and can hold fares at a reasonable cost, it has an excellent opportunity to convert private passenger car riders to its service.

There are numerous opportunities for the integration of taxicabs, transit, and intercity buses that can result in substantial fuel savings and encourage ridership by providing more efficient public passenger services.

The taxicab industry is desperately looking for some encouragement from the Federal Government to remain in the private sector of public passenger transportation and to continue to invest capital, time, and effort. The Federal gasoline excise tax is a major impairment to this industry. The industry desires equity and recognition at this time.

Thank you, Mr. Chairman, and members of the committee, for giving me the opportunity to present the view of the taxicab industry.

The CHAIRMAN. What is your reaction to that ad I saw on television that indicated if you drove a Volkswagen Rabbit you would not have any problems, you would cut your energy costs in half?

Mr. GLASSMAN. I cannot comment, sir, on the efficiency of that vehicle. I have not been able to test it myself.

The CHAIRMAN. Senator Packwood?

Senator PACKWOOD. No questions.

The CHAIRMAN. Senator Hathaway?

Senator HATHAWAY. Is this not testifying against the gasoline tax, but not the gas-guzzler tax?

Mr. GLASSMAN. What we are really asking for is that our industry be given the same exemption that was given to the intercity bus and the schoolbus in excise tax rebates

Senator HATHAWAY. I see. The gas-guzzler tax does not bother you?

Mr. GLASSMAN. No, sir. We will only be able to purchase the automobiles that are available on the market. The cars some of us are using now have until 1979, exemptions. We basically use standard automobiles, 6-cylinder cars, in most instances.

Senator HATHAWAY. Thank you.

The CHAIRMAN. It seems to me if you want to get the exemption, you have to be willing to do something for it, and that the condition should be that you go in for smaller, more fuel-efficient automobiles. That would seem to me to help meet your problem, and reward you for doing it all at the same time.

Mr. GLASSMAN. Mr. Chairman, it so happens that I believe all of our operators are very fuel conscious. We attempt to, through good prevention maintenance. Most of the cab companies do have a concern, and the maintenance charts will show that automobiles that are strictly city driving, stop and go, we do have a pretty high miles per gallon on our vehicles.

The CHAIRMAN. You are not necessarily driving automobiles which get good mileage. Is it possible to grant you an exemption along the lines you are asking for on the condition that you do something in return. Maybe we can make it easy for you and help you to change to small automobiles.

A lot of taxicabs I have seen are older cars, and while they will get there all right, they are pretty much the worse for wear. I hate to say it, but in my hometown, it seems as if the fellow put into service what was the worst, old, beat-up automobile that can be found in a used car lot anywhere. If they would use a new automobile, we would have better service and also have a smaller cab that would be fuel efficient.

Why can your industry not move toward the smaller automobile, if we give them the exemption you are asking for?

Mr. GALLAGHER. I would like to call your attention to the fact that most of the automobiles that we use are standard stock cars. We do not have automatic transmissions in a great number of them; we do not have electric windows, as you mentioned prior. We do try to get the best gasoline consumption.

Right now, they are testing Aspens for gas consumption. They are testing diesel engines in taxicabs—not supported by the manufacturers, but supported by industry and partly by DOT grants. We are very conscious of the fact that we need better production.

If you look at the attached statements, in a number of communities they are suggesting share-a-ride programs which can increase our productivity. If you translate the amount of gasoline we consume to the amount of passengers we handle, you will find per gallon of gasoline, we handle approximately 3.4 passengers, which I think is a good record, and we certainly could improve that substantially if we could get some of the communities to relieve us from some of the regulations that exist on shared rides.

We have been making this move. We have been working for DOT. They have done several reports, and various other consultants have done reports.

We have numerous programs going on. In Montgomery, Ala., they have a shared ride program now for the elderly and the handicapped. Our problem is that we are in competition with transit, and transit is moving into the area of demand response.

We can deliver the service for approximately one-half the cost, at the present time, and we would like to stay in that position of being competitive.

If it continues in that direction, you are going to create another competition for the taxicabs, which is—what do you call it? Paratransit, which is going to be under the control of the transit authorities, who are now losing at the rate of $1.7 billion per year. So we are at the point in our industry where we cannot afford this competition. We cannot give advantages in competitive situations.

The CHAIRMAN. My idea is that one way to fight competition is to become more competitive, to cut expenses. I am all for the shared-ride concept. You could do that and still move to a smaller, more efficient use of energy in your industry, and that is all I am talking about.

I am suggesting that everybody do his part toward making more efficient use of energy on a passenger-mile basis. You contend that you can move passengers, on a passenger-mile basis, below the cost of moving them by bus?

Mr. GLASSMAN. Yes.

The CHAIRMAN. The buses say they can give us 200 passenger-miles per gallon. How much do you provide?

Mr. GALLAGHER. In those terms, Senator, we cannot, but if you take a vehicle that carries from three to five passengers per trip, the small, standard stock car would have a better efficiency performance in the taxicab industry than a bus.

It is a question of load factor. Our load factor, at the present time, is 1.8 passengers per trip. In World War II when we had shared rides, it got up to approximately 2.3.

We would like to—we have some companies which are currently experimenting. They are at 2.6. When we get to that point, we are highly efficient in the use of gasoline.

The CHAIRMAN. I hope we can do things that can make the community cooperate with you in ride-sharing.

Let me ask you, if we used the ride-sharing concept and someone wanted to get in the cab and not pay more money and not fool around with sharing rides, would he have that privilege?

Mr. GLASSMAN. Under some of the current systems, yes, sir, they have the choice of exclusive ride or shared ride.

The CHAIRMAN. Thank you.

Are there any further questions, gentlemen?

Thank you very much.

[The following attachments were submitted by Mr. Glassman:]

94-548—77——6

EXHIBIT A.—COMPARATIVE STATISTICS: TAXICAB, TRANSIT, INTERCITY BUS, YEAR 1975

	Taxicab[1]	Transit[2]	Intercity bus[3]
Number of operating companies and authorities	5,387	947	950
Number of vehicles	298,000	62,271	20,500
Number of workers	634,000	159,800	46,000
Passengers—billions	3.4	5.6	0.35
Vehicle miles—billions	12.2	2.0	1.1
Operating revenues—billions	$5.2	$2.0	$1.2
Operating expenses—billions	$4.6	$3.7	$1.1
Communities served	[4] 3,361		[5] 15,000

[1] Source: All figures from "Taxicab Operating Characteristics," Prepared by Control Data Corporation, Wells Research Co., for U.S. Department of Transportation, 1977.
[2] Source: All figures from "1976 Transit Fact Book," American Public Transit Association (Washington, D.C., March 1976).
[3] Source: All figures from "One-Half Century of Service to America," National Association of Motor Bus Owners (Washington, D.C., 1976).
[4] Incorporated only, communities over 5,000 population.
[5] Includes cities, communities, villages, and other places, incorporated and unincorporated, in the United States.

Exhibit B

COMMENTS BY VARIOUS GOVERNMENT AUTHORITIES, CONSULTANTS AND RESEARCH ORGANIZATIONS ON THE ROLE OF TAXICABS IN PUBLIC PASSENGER TRANSPORTATION

"Often overlooked in the investigation of urban transportation services is the taxi industry. While most persons are familiar with the standard premium type service offered by taxi companies, they are generally unfamiliar with the extent of service provided and the role of this service in providing for the daily trip movements within an urban area. If greater coordination of taxi service with other modes within the total transportation picture is to be provided it must be based upon a thorough understanding of the taxi industry."[1]

"Since taxi companies have considerable experience in operating efficient demand-responsive transportation systems, they should be given an opportunity to operate any additional demand-responsive system deemed necessary in the Twin Cities Metropolitan Transit Taxing District including specialized handicapped and elderly services. It is suggested that the MTC be responsible for the assurance of service and coordination of all demand responsive transportation services including specialized elderly and handicapped transportation services acting as a brokerage agency to match these services to the demands without regard to ownership and operation of any particular mode."[2]

"Should taxis be utilized to perform public transit services either in coordination with or in place of current transit vehicles, these services should be made eligible to receive Federal and State financial aids currently available to conventional transit systems. Such financial aids might include exemption from the payment of gasoline tax, operating subsidies as required to perform such services and guarantee a fair profit margin and capital-grants-in aid."[3]

"It is realized that the taxicab industry would prefer a minimum of Government involvement; however, the emergence of the fuel crisis in 1974 and continued inflationary spiral has placed most taxicab companies in a serious economic situation.

"When faced with similar problems and a decline in passenger demand over the last ten years, the bus and rail transit industry was transformed from a private to a public sector dominated industry. Thus far, this transformation has not happened with the taxicab industry, and most operators do not appear to want this to happen. On the other hand, the industry is finding it more difficult to cope with the increasing pressures.

"The desire to survive as a private enterprise still exists, but the lack of funds to provide the information and research needed by the industry is leading to a general feeling of frustration."[4]

"Compared to urban bus systems or private, non-profit transportation for elderly and handicapped persons in urban areas, taxis rarely receive government assistance. Only in a few cities and villages in Wisconsin have private taxi firms received such aid. In May, 1976, however, subsidized service began in Ripon, and the City of Waukesha is giving serious consideration to replacing its abandoned fixed-route urban bus system with subsidized taxi service. It may be the case that local governments are becoming increasingly willing to participate in programs involving taxicabs in which the governments have a financial commitment."[5]

"Taxi firms in Wisconsin are subject to many state and federal taxes for which other transport modes have been granted exemptions. For example, the taxi industry in Wisconsin appears to favor an exemption from the state's 7 cents per gallon fuel tax, that is now paid by taxi firms but not by urban bus systems."[6]

"In many cases it appears that the lack of taxi participation in state and federal programs is more a matter of oversight than of deliberate exclusion. Urban planning studies have only recently begun to include taxis, and local, state, and federal governments are now becoming more sympathetic to the needs and abilities of private taxi operators."[7]

"In Pittsburgh, Pennsylvania, Allegheny County, the average social agency was operating at $1.28 per mile up to $3.45 per mile as indicated by the Area Agency for the Aging in Allegheny County. We were willing to operate their vehicles for 60 cents per mile and we are now in the process of doing it. The United States Government, under 16(b)(2), dumped tons of transportation equipment into Allegheny County and their cost of operation in one particular nonprofit corporation was $20.26 per passenger. We could do it for $2.42 per passenger and give better service."[8]

"Many companies operate more than just four-door sedan taxicabs. We have had wheelchair van service for several years; we call it Medi-Cab. We instituted a 20 percent discount for senior citizens several years ago. The mix of our operating fleet includes wheel chair vans, school buses, Cadillac Limousines, mini-buses and thirty-five Yellow Checker Cabs. We estimate we carried 400,000 passengers in 1976 and delivered about 59,000 packages from telegrams to computer parts. We are truly a Para-Transit service company.

"We are supporting ourselves, serving the public and industry, providing jobs and serving the special needs of the elderly and handicapped without subsidy. And we are paying taxes. I wonder how many of the programs you are proposing and hearing about intend to do as well."[9]

"This service competes with me in Red Bank where we began our discount program and also allow two to ride for the price of one. The SCAT system had its best month in June and its cost was $1,066 to carry 369 passengers-trips as opposed to less than $300 for the use of our taxicab system. So the taxpayers are getting it in the wallet and a private business in subsidizing its competition." [10]

"In addition, under my proposal, dispatch system swould be located at the town and city levels running off a centralized computer system maintained in Nassau County. I have discussed this proposal with the program director of the Dial-a-Ride at the U.S. Department of Transportation in Washington and found this proposal to be feasible, both in terms of cost and implementation. In California, such a system is already in operation.

"I see the implementation of a taxicab demand-response system as an immediate and realistic approach to many of our transportation woes. I am prepared, as I have been in the past, to offer any assistance necessary to implement this program, or other approaches that will promote better transportation throughout our region." [11]

"The private taxi industry now serves more fare-paying passengers on an annual basis than all rapid transit systems. I can imagine no worse eventuality for transit authorities than the disappearance of private taxi companies and a resulting pressure on public authorities to provide similar kinds of service with public subsidies. There is simply not enough public financing capacity to support public transit if the authorities must also serve the population and trip purposes that are now served by the taxi industry." [12]

"As one of the 'para-transit' modes, taxicabs make an important contribution to urban transportation. In addition to several thousand individual operators, there are currently (June, 1974) about 7,200 fleet operations in the United States. These fleets operate in about 3,300 communities and in many areas are the only form of public passenger transportation available.

"Taxicabs are used by persons with a wide range of socio-economic characteristics. Senior citizens are heavy users of taxicabs, especially in incorporated urban areas. In these areas, persons aged 60 and over represent 9.6 percent of the sample population but account for 21.7 percent of the taxicab trips. Taxicabs are also used extensively by handicapped persons, low income workers, housewives, executives and white-collar workers." [13]

"As will be seen in this report, the transportation needs of the elderly are usually best served by some form of demand-responsive door-to-door service. It is not surprising that (according to studies cited in this report) taxis are such a popular mode of transportation with older people since taxi service is in fact demand-responsive and door-to-door. From a review of over 900 transportation projects for older American [1] it has been possible to identify the type of service for about 313 projects. Of these, some two-thirds (200) were operating entirely or in part as demand-responsive service. Eleven instances were found of (subsidized) reduced fare taxi service for the elderly." [14]

"*Taxi user characteristics.*—The survey produced data on a large number of taxi user characteristics. These are summarized in Figure 5 along with comparable data from the 1970 Census.

"Compared to the population of the eight cities, the taxi riders have lower incomes, have fewer cars, are more likely to be elderly, are less likely to have white collar jobs, and are more likely to be non-white. These characteristics are in some cases dramatic. Whereas 11.4 percent of the households in the eight cities earn less than $3,000 per year, three times as many taxi passengers are in this category. For incomes between $3,000 and $5,000, the percentage of taxi riders is two times the percentage of households in this category. In fact, over one-half of all the passengers are from households earning less than $5,000 per year. Conversely, at the other end of the income scale, the result is reversed. Although 42 percent of the households earn more than $10,000 per year, less than one-half as many taxi users are in this category. Clearly, taxi users in these cities are predominantly poor.

"The other user characteristics consistently confirm this conclusion. For instance, nearly three out of every four taxi users have no driver's license; almost six out of every ten passengers are from a household with no car; and eight out of every ten passengers have no car available for the trip during which the interview took place. These facts indicate the taxi users to be predominantly autoless, which for four of these cities means that the users are also taxi-dependent." [15]

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[Thereupon, at 12:55 p.m., the hearings in the above-entitled matter were recessed, to reconvene at 10 a.m., Thursday, August 11, 1977.]

ENERGY TAX ACT OF 1977

THURSDAY, AUGUST 11, 1977

UNITED STATES SENATE,
COMMITTEE ON FINANCE,
Washington, D.C.

The committee met, pursuant to notice, at 10:05 a.m. in room 2221, Dirksen Senate Office Building, Hon. Russell B. Long (chairman of the committee) presiding.

Present: Senators Long, Matsunaga, Packwood, and Roth, Jr.

The CHAIRMAN. The committee will come to order. Other Senators will be along shortly.

Meanwhile, I am going to call the first witness, Mr. W. Reid Thompson, vice chairman, Edison Electric Institute.

We are very happy to have you here with us today.

STATEMENT OF W. REID THOMPSON, VICE CHAIRMAN, EDISON ELECTRIC INSTITUTE

Mr. THOMPSON. Thank you, Mr. Chairman.

I appreciate the opportunity to testify here today, Mr. Chairman, on behalf of the Edison Electric Institute. That organization represents 99 percent of the investor-owned power companies in the United States who in turn serve about 78 percent of all the electric customers in the country, and I appear on behalf of that organization.

Additionally, I am chairman of the board of the Potomac Electric Power Co., the local power company in Washington.

We would like, Mr. Chairman, to make just four points for your consideration with respect to the energy tax provisions of the National Energy Act.

The first point that we would like to urge upon this committee—and urge you strongly, Mr. Chairman—is not to enact the user tax provided in this bill. We strongly oppose that tax, for the following reasons:

First of all, present law, particularly the act known as the Energy Supply and Environmental Coordination Act of 1974, provides for the FEA to mandate conversion from oil and gas to coal in facilities that are feasible to be converted. That program is underway in full force. The National Energy Act continues that program.

This user tax, Mr. Chairman, in effect says——

The CHAIRMAN. I wonder if you could back up and start again, so that Mr. Packwood can hear your entire statement. He is only 1 minute late, because I was 1 minute ahead of him.

Mr. THOMPSON. Thank you, Mr. Chairman.

The CHAIRMAN. Start your point again about the user tax.

Mr. THOMPSON. The Edison Electric Institute opposes the user tax. The first principal point, under the present National Energy Supply and Environmental Coordination Act of 1974, which provides for the FEA to mandate conversion of utility generating plants from oil and gas to coal, that program is presently underway.

The whole thrust and purpose of the program is to provide for mandatory conversion where it is feasible to convert.

Additionally, the National Energy Act prohibits any new plants from being designed to burn either oil or gas, so that this energy user's tax is, in effect, a tax which says, if you cannot convert to coal, then we will tax you in order to stimulate you to do so. It is designed not to be a revenue measure, so the administration says.

Now, that being the logic, you could infer from the Act—I have heard it is said by certain of the administration officials that the user tax is designed to encourage early retirement of plants, recognizing that it will not result in any significant conversion other than that already being done.

It has not been said to me directly, but I say to you, Mr. Chairman, if that is being advanced as the rationale for this tax, it is an incredible lack of appreciation for the capital resources committed to those plants and the burden on the ratepayers of this Nation.

In other words, if it said that, by the imposition of the tax, an artificial additional economic burden, you will thereby be encouraged to early retire a unit, earlier than it needs to be retired, then I say to you, sir, that is a wastrel attitude toward the productive resources of this Nation.

We would assert that oil and gas are not the only things worthy of conservation in this Nation. Viable, good productive capacity is worthy of conservation. The money of the electric ratepayers of this country is worthy of consideration, because, if you replace oil or gas costing $75 to $100 a kilowatt built 10-years ago with a coal-fired plant today, which is costing $600 to $800 a kilowatt, $1,000 a kilowatt for nuclear capacity, I say to you, sir, if you retire a plant before it should be retired for technological and economic reasons because of this so-called artificial stimulus, you are wasting the assets of the Nation.

Now, a third point: this is a very inequitable tax. It falls, Mr. Chairman, on people from your part of the country who burn gas, in the southwest. It falls on the people in New England and the coastal States who burn oil, not because they prefer those fuels but because in the past they were the most economic and also, Mr. Chairman, because it was the patriotic thing to do in years past.

My company, for one example, burned all coal until 1968, nothing but coal. We shifted, starting in 1968, to move as fast as we could into conversion to oil because it was more economic and because we were required to do so by the environmental requirements of this Nation.

We got one unit converted so it could burn oil, and just as we got it converted, that requirement shifted 180°—we never burned a drop of oil, but we continued to burn coal.

I say to you that it is inequitable in its effect because it hits only those companies who, for past good reasons, have designed their capacity to burn oil and gas.

Now, the final and most significant point about this user tax is this: it is not at all necessary, Mr. Chairman; it will not do the job that it is designed to do. It is not at all necessary for this reason: The economics are already such that it pays to convert to coal when you can; the law mandates it. There will be no new gas burning plants in the future. Let me give you the statistics to show you what I am talking about.

Without any National Energy Act, here is what is happening with respect to the burning of gas by electric utilities. In 1976, 15 percent of the natural gas burned in this country was burned by utilities; only 15 percent, which accounted for 6 percent of the electric power generation. But plants already underway, without this act, will provide that in 10 years, in 1986, only 6 percent of the natural gas being used will be burned by utilities. Instead of 12 percent of the electric generation being by natural gas, only 3 percent will be so generated.

The CHAIRMAN. What percentage is being generated by gas now?

Mr. THOMPSON. 12 percent of the electric generation today is by natural gas.

The CHAIRMAN. 15 percent?

Mr. THOMPSON. Of the gas burned in the Nation.

The CHAIRMAN. 12 percent is burned by electric utilities?

Mr. THOMPSON. By natural gas.

Plans are already underway to bring that down to a 6-percent use and a 3-percent generation.

Senator PACKWOOD. Let me ask you about a statement you made. You said that under existing law, any plant that can be converted to coal must be converted to coal?

Mr. THOMPSON. The FEA can mandate conversions and has done so. The only thing that has stymied the full operation of that plan, as far as I know, in converting all plants that are capable of burning coal to coal is the Environmental Protection Agency in applying the provisions of that act which entered the picture at points, saying you cannot convert because of the environmental problems associated with it.

Where you can convert, you convert.

Senator PACKWOOD. Where it can be converted, is FEA forcing you to convert even though you have good economic life in the plants that you are running on oil and gas?

Mr. THOMPSON. Oh, yes, Senator Packwood. The units that we are talking about converting are those that have coal-burning capability, units that either can burn either fuel with relatively little additional capital expenditure, some to be sure.

The difference is this: It is estimated that 114 units in this country which were burning oil——

Senator PACKWOOD. Were what?

Mr. THOMPSON. Were burning oil, were capable of burning coal reasonably economically with some additional expenditure. Of those 114, my understanding is that 92 of them are under orders by the FEA to make that conversion. These others are relatively small or for some reason have not been considered by the FEA. Some of those 92 have been exempt, Senator, because of environmental considerations.

The difference is this: When you talk about conversion of a gas facility to coal or nuclear plants, you are not talking about conversion you are talking about replacement. To convert a gas facility, you build a new plant right beside the old one, that is how you convert it.

FEA is not empowered to order that, and it should not be.

Senator PACKWOOD. I want to get it straight in my mind what you said about the user tax, in that it is going to be a tax on you on plants that you cannot convert?

Mr. THOMPSON. Exactly.

Senator PACKWOOD. Is the user tax economically going to cause you to convert any plants that the FEA is not going to order you to convert anyway?

Mr. THOMPSON. My answer to that is no, it will not. I cannot.

If the user tax, because of the tremendous, heavy impact of it, causes you to abandon another plant and build a new one instead earlier than necessary, I feel that that is an uneconomic waste of resources.

Senator PACKWOOD. Are you saying if the user tax causes you to do that, that is a plant that you would convert, you would not otherwise convert, but apparently FEA is going to make you convert?

Mr. THOMPSON. Convert is not the word for that.

Senator PACKWOOD. I will use your word.

Mr. THOMPSON. Replace.

Senator PACKWOOD. Replace.

Is this user tax going to make you replace any plants that the FEA would otherwise make you replace?

Mr. THOMPSON. It is conceivable in some companies, you will hear direct testimony from people from Texas, for instance, which are gas-burning today—it is conceivable that the impact of that user tax is of such tremendous magnitude that it would cause that, yes, sir.

Senator PACKWOOD. In this sense, if the purpose of the tax is to force you off gas or oil, it might work?

Mr. THOMPSON. Yes, sir. If it did, it runs exactly counter to the whole thrust of the President's proposal, to do something about the potential energy shortage in the Nation. It runs counter to the whole thrust of the President's proposal with respect to capital formation difficulties that the utilities are having in this Nation.

Senator PACKWOOD. I understand that we are capital short all through industry, not only in the utility industry. I realize that if you have to retire a plant 10 years before you should, that is a capital expense you would not have to make.

If it saves 50,000 barrels a day, that is a plus.

Mr. THOMPSON. I do not think that is a plus. I think that is a total minus on the tradeoff, because, while oil and gas are in some state of scarcity, to be sure, we are not totally out of them. That 50,000 barrels you referred to, Senator, it ought to be burned in that plant rather than used someplace else, in all the tradeoffs.

Senator PACKWOOD. You may be right. That is where the issue is coming. I am going to have an extensive meeting this afternoon with USGS on the available oil in this country and whether or not there is enough to make this transition gradual.

If there is not enough oil, we may have to force that conversion. We may have to find some way to conserve oil. This is one fashion, at an economic cost we would not make if there was adequate oil.

Mr. THOMPSON. If that is the case, if that is truly the case, and I assert it is not, let us deal with it directly. Let us face it head on and say we are prepared to have electric shortages in this country. Because I say to you, sir, that the best available figures indicate that in 1980 or 1981 we are going to face some potential electric power shortages in this country. We are working as hard as we can to build the plants that we need anyhow without replacing perfectly good ones that are doing the job today.

Senator PACKWOOD. Let me ask the question once more so I understand. The user tax might indeed economically force you to convert or replace some plants that you would not otherwise replace, at least until their economic life was over and they are not plants that FEA at the moment would force you to replace?

Mr. THOMPSON. I am not at all certain that is the case. I am not at all certain. I have no statistical figure that would indicate that. I say to you, Senator Packwood, if it would force anybody to do it, it would force somebody like Houston Power & Light or Texas Utilities. The chairmen of both of those utilities will be testifying here in a moment.

Senator PACKWOOD. Let's put it the other way around. I have no desire for the Government to collect more money just for the sake of collecting money if it does not achieve conservation. If, indeed, the FEA in their directive is going to achieve 98 percent of what could be achieved with this user tax without the FEA, I am not for the user tax.

Mr. THOMPSON. I think, sir, that you will vote against it.

Let me make another point in my short time here which I think is very important with respect to this user tax. We hope and trust that this committee will not buy that tax. If, perchance, you did enact it, it has some grave faults about it. Two of them I will mention.

One is that it results in a net higher electric cost to utility customers even though the avowed purpose is not to be a revenue collector. That is for this reason. If a company installs so-called qualified plant expenditures to offset that tax, it gets 100 percent credit against that tax. In other words, if you pay $50 million in user tax, and you built $50 million of qualified replacement equipment, you have offset the tax and get the tax back. But, sir, you lose the investment tax credit that you would have gotten without it for building those facilities. You lose the entire old 10-percent investment tax plus the 1.5 percent ESOP, Mr. Chairman.

The net effect of enacting this user tax is even if you offset it completely, you have lost all the benefits of the old—not the new 10 percent, the old investment tax credit and the ESOP that you would have gotten without that new tax. You do not offset it. You do not end up with an offset, as is stated to be the purpose.

The purpose is to be a revenue collector. It has to be revenue collecting; to that extent it hurts the utility in its financial posture, and we would urge that if it is enacted, God forbid, at least it be amended to preserve the old 10-percent investment tax credit and the ESOP, and it should only lose the new additional 10-percent investment tax credit which you had as an opportunity.

Senator PACKWOOD. What does the administration project will be the oil savings of this forced conversion by the user tax on utilities?

Mr. THOMPSON. I do not know, sir. I do not have that figure before me. I have a curious figure before me. In the report put out by the staff of the Joint Committee on Taxation 2 days ago, a curious figure which they project. That figure may be in here, as to what they project the total dollar cost would be to the utility and the net benefit to the Treasury.

Senator PACKWOOD. What do they project?

Mr. THOMPSON. They project—this is a curious thing—in 1984, the first full effective date of tax, they proje t $98 million as being the net benefit to the Treasury.

Senator PACKWOOD. In that year?

Mr. THOMPSON. In that year from utilities. We project the gross figure to be $2 billion, not $98 million; 20 times the 98 is the imposition of the tax. They do not dispute it. To get from the $2 billion to the $98 million, they deduct the rebate that you get for building these facilities which they say will result from it—we say it will not.

The next curious thing, Senator, they also deduct "income offset." Explaining what they mean by that, on table 4, with respect to industrials—they do not explain it for utilities. On industrials, they say in the year 1983, for instance, that the gross effect of the tax will be $4.6 billion to the Treasury, but that they will pay out $3.9 billion in rebates and another $96 million for this: "Reductions in income tax liabilities of businesses resulting from less than full pass-through of tax to prices," in other words, reduction of the profits or earnings of the business because of this tax, and exacerbating the capital formation problems that this committee has dealt with time after time after time with grave concern for the future of industry in this country. On the face of it, these tables say, if this tax is enacted, it will result in reduced earnings to those industries affected by it.

Now, one final point that I would like to make, Mr. Chairman, is if this bill is enacted, we think certainly you should also look carefully to expand the exemptions under the bill. At present the only exemption that we say with any certainty is in the bill is an exemption if you are required by certain environmental requirements by the State or Federal Government to burn oil or gas.

The House committee report contains some language that it was the intention of the House in passing that bill to provide a broad exemption to be granted by the Secretary of the Treasury when certain economic disadvantages occur, and the like. We think that should be written into the bill.

Finally, I should say to you, Mr. Chairman, that the electric utility industry is committed to oppose the crude oil utilization tax. That is an additional tax burden on the electric users and those utilities who do generate electricity by oil and gas.

That concludes my statement, sir.

The CHAIRMAN. I was looking at the summary document prepared by the joint committee staff. I am looking at two things.

First, I am looking on page 39 at the revenue analysis of the excise tax on business use of oil and gas under title II. It does not indicate a significant pickup of revenues, not in terms of what the entire bill involves. The biggest revenue effect would be in 1985 when the pickup would be $784 million. Even over the whole period of effectiveness, it would be $2.16 billion.

Mr. THOMPSON. Look at table IV and see how they arrive at that figure. That $784 million is not the gross effect of the tax, by any means.

Table IV on page 39, two tables over, shows that figure instead of being $784 million, the gross effect in that one year is $6.6 billion, and the accumulative effect is $25 billion.

What they do then is net out——

The CHAIRMAN. Look at the top of the column on page 39, "gross tax before rebates for qualified investment," that grosses out to $25 billion from 1979 to 1985. Then there are rebates for qualified investments, $21.9 billion. There are also reductions in income tax liabilities of $488 million.

Mr. THOMPSON. That means loss of profits to the business this is going to impose——

The CHAIRMAN. That nets to $2.76 billion for the 6-year period, so that it would not appear that there is, on the overall program, the estimated large gain in revenues. There is a $2.7 billion revenue gain from a heavy tax, a tax that starts out as a $25 billion tax, but only nets 10 percent. It is not much of a revenue raiser.

EXCISE ON TAX BUSINESS USE [1] OF OIL AND NATURAL GAS UNDER TITLE II OF H.R. 8444, AS PASSED BY THE HOUSE: RELATIONSHIP OF GROSS TAX TO NET EFFECT ON BUDGET RECEIPTS, FISCAL YEARS 1979-85

[In millions of dollars]

	1979	1980	1981	1982	1983	1984	1985	Total, 1979-85
Gross tax before rebate for qualified investment		1,734	2,796	3,642	4,678	5,605	6,638	25,093
Rebate for qualified investment		−1,298	−2,686	−3,421	−3,990	−4,780	−5,714	−21,889
Reduction in income tax liabilities of business resulting from less than full pass-through of tax to prices	−25	−38	−22	−57	−96	−110	−140	−488
Net effect on budget receipts	−25	398	88	164	592	715	785	2,71

[1] Other than utility.

On the other hand, if you look at the projected energy savings of that provision, it is significant. I am looking at the last page, page 42 on the back of the pamphlet "Estimated Energy Savings of Major Tax Provisions of Energy Bill." I will ask for that column to appear in the record at this point.

TABLE 1.—ESTIMATED ENERGY SAVINGS OF MAJOR TAX PROVISIONS OF ENERGY BILL (TITLE II OF H.R. 8444) IN 1985

[Range of savings in equivalent of 1,000 barrels of oil per day]

Provision:	House bill
Residential insulation and solar tax credits:	
Insulation	245- 295
Solar	25- 35
Subtotal	270- 230
Transportation tax provisions:	
Gas guzzler tax	140- 210
Extension of existing gas tax	35- 45
Subtotal	175- 255
Crude oil equalization tax	430- 650
Business use tax and energy investment tax credits	830-1,250
Other (geothermal)	6- 11
Total (range)	1,711-2,496

This table estimates a total range of energy savings for the bill of somewhere between 1,711,000 barrels a day and 2,496,000 barrels a day, and the largest single item seems to involve the business use tax and energy investment tax credits. The table estimates those provisions would save between 830,000 and 1,250,000 barrels per day.

If that is correct, of course, that is a strong showing against your argument. If I understand what you are saying, you are saying that conversion to coal is what business would do anyway, because they are mandated to do it under existing law.

Mr. THOMPSON. I cannot address, Senator, the question as to the effect generally on the industrial sector, because I have not looked into that. As to the utility portion of it, I say exactly that the utility industry is moving to do what it can do.

What this shows on the utility side of it is at a very minimum, a net cost from utilities for the whole period of $488 million to the Treasury, after netting out these so-called rebates.

I say to you two things about that. I have grave doubt about the validity of these projected figures. It is very simple for somebody to sit down and make all sorts of projections for a 10-year period as to what is going to happen. What the assumptions are to produce those figures I do not know.

I say to you that there will not be that much conversion caused by this bill to justify the tax, but I say something else to you, which I think is very important to you, Senator. I must reiterate it. We must conserve gas and oil in this country but not at any kind of price.

The other things are worth conserving, too. Capital is worth conserving. I say to you if we have to build a $1,000 megawatt plant to retire a plant that cost $100 megawatts burning oil or gas, that is not economic. That is not the kind of conservation we should do in this country.

Gas and oil are not the only things worth saving. We need to conserve to be sure——

The CHAIRMAN. In other words, the value of the plant that you are junking and the cost of the alternative ought to be considered in connection with the rate at which you junk that plant?

Mr. THOMPSON. Yes.

Let me make one other point. This is very important. Other provisions of this act mandate that there not be 1 cubic foot of natural gas burned by a utility after the year 1990 or 1995, not a foot after 1995; after 1990, in some versions.

It is estimated to replace those facilities—that is mandated; nothing to do with tax—to replace those facilities—which is about 40,000 megawatts—is going to cost $40 billion to the electric utility industry between now and 1995. You say some of those plants are getting kind of old, approaching retirement anyway. That is true, but it does not mean that you could not still use them, even if you only used them for a few hours a year for peaking purposes, which you cannot do under the bill. You have to replace it with capacity which will be there for peaking purposes.

I say you already have a $40 billion burden on a selected few utilities who burn gas to get rid of all that gas by 1995. What this does in the interim, between now and then, is put a tremendous tax burden on them to theoretically, have them get rid of them a few years sooner?

Theoretically, you will have testimony from people in Texas that it will not happen. It will be a net cost of hundreds of millions of dollars to their customers on account of this bill.

The CHAIRMAN. When I came to Washington, we were estimating there was enough natural gas to last for 23 years. It is embarrassing to tell you how long I have been here; it has been 29 years.

Mind you, we started off with enough proven reserves to last us 23 years; it has been 29 years. Now they tell us there is enough to last us about 11 years.

I subsequently learned something that Senator Packwood made reference to yesterday. How much you have depends on how much you are willing to pay for it. If you are willing to pay a higher price for it, that 13 years becomes 26 years all over again in a hurry, because a lot of gas is more expensive to produce.

In Louisiana, people have done some estimates and have testified before our committee, and what they tell us is that if you drill down to somewhere between 20,000 and 25,000 feet and you tap hot water, hot brine at about 450 degrees, that there is a lot of methane gas in it. If you can recover 5 percent of that gas, that will provide enough gas at the rate that we are presently using gas to last us 300 years—300 years, not 23—300.

It does have some problems. There is a corrosion problem. There is a problem about what do you do with hot water that comes back up. I have had a number of thoughts about that. It might be useful in environmental control, like producing nice warm water. If we put a bulb over that, I think we could even get people to leave Florida and come to Louisiana and let them swim in beautiful, clean salt water, at whatever salinity they want, at whatever temperature they like, in the water and outside of the water. During the wintertime, that would have to have Florida beat. Their water gets a little cold in the wintertime, and its gets very chilly when you get out of the water. We could have a series of lakes to float this controlled environment down to the Gulf of Mexico, and we would have a paradise in Louisiana for the next 300 years.

We are going to make breakthroughs in that area. The experimental results that are coming in tend to prove the feasibility of this concept, although there are technical problems to overcome. We could make great progress if we put the kind of talent to it that we put on the effort to the Moon, but right now we are not making any serious effort with it. You might say we are just playing around with it—when I say "we," I mean the Government, who has the money for it. There are more interested in other things.

If we concentrate on it and make it a priority, it would seem to me that there is no way that they could fail to develop geopressurized methane. Instead of having you convert to coal, I think after awhile we would be asking you to convert back to gas, which is par for the course for a Government program.

Mr. THOMPSON. That is why I say we ought to keep some of those gas furnaces to burn some of that gas where we have these facilities to burn the gas.

The CHAIRMAN. When you are in New Orleans, let me know, because there are fine people down there, including some people in your business, some of whom are here to testify. We have a saltwater swimming pool over at the athletic club. The only problem with it, it does not go down deep enough, the water is not hot enough.

We know where to get it; all we have to do is drill down a little bit deeper. You can see what it is like to swim in a nice, saltwater swimming pool. You float better than in a freshwater pool.

Mr. THOMPSON. Thank you very much, Mr. Chairman. I appreciate your attention.

The CHAIRMAN. All right.

[The prepared statement of Mr. Thompson follows:]

STATEMENT OF EDISON ELECTRIC INSTITUTE

SUMMARY

1. The Edison Electric Institute believes that an effective national energy policy must be adopted so that our continued economic development, decreased dependence on foreign fuel and a better life for all Americans can be realized.

2. Incentives to increase the development and wise use of domestic energy are necessary but are not in H.R. 8444; conservation alone will not be sufficient to achieve our national energy objectives.

3. We urge that the equalization tax and the user tax be deleted from the bill.

4. The bill recognizes in Title I that various conditions will result in exemptions from reqirements to convert from oil or gas to coal as a boiler fuel. Despite this Title II imposes a punitive tax on fuel burned in these facilities even though no other feasible fuel option exists. Today's high cost of oil and gas is already bringing about a phase-out of those fuels and a tax on them will not promote conservation but will increase the cost of electricity.

5. Regional inequities will be created by taxes proposed by the bill. Customers in some areas of the country will pay more tax in their electric bills because of the type of fuel burned but would not receive rebates in the same proportion as paid.

6. We recommend that this Committee overturn the "Corman Amendment" as passed on the Floor of the House and support the Ways and Means Committee in granting an exemption from user taxes in specified exempt facilities.

STATEMENT

I am W. Reid Thompson, President and Chairman of the Potomac Electric Power Company, which serves the District of Columbia and parts of Maryland and Virginia. I appear here today on behalf of the Edison Electric Institute. EEI is the principal national association of investor-owned electric light and power companies in the United States. Its member companies serve 99 percent of all customers of the investor-owned segment of the industry and 77.5 percent of all users of electricity in the country. Thus, the Institute's members and their customers are directly affected by Congressional action on H.R. 8444, the "National Energy Act."

We believe that an effective national energy policy must be adopted so that our continued economic development, decreased dependence on foreign fuel and a better life for all Americans can be realized. We urge that incentives to increase the development and wise use of domestic energy resources are necessary; conservation alone will not be sufficient to achieve our national objectives.

As of 1976, some 93,000 megawatts of steam-electric generating capacity in the United States were oil-fired. This includes approximately 20,000 megawatts in units capable of conversion to burning coal without complete reconstruction of boilers and fuel-handling facilities. Gas-fired steam capacity amounted to about 59,000 megawatts of which only 2,000 megawatts is convertible to coal without major rebuilding.

There is also scheduled for commercial operation between 1977 and 1985 an additional 16,500 megawatts of oil-burning steam-electric capacity and 1,000 megawatts of gas-fired steam plant. Little, if any, of this scheduled capacity, now mostly under construction, is capable of conversion.

Thus, less than 15 percent of oil- and gas-fired generating capacity is capable of conversion without an almost complete reconstruction of boilers and fuel-handling facilities, the cost of which would greatly exceed the total original cost of the plant.

If measures relating to electric utilities in H.R. 8444 are enacted and implemented, the Nation's electricity users would face a significant additional cost burden. Billions of dollars of investment would be required to replace existing oil- and gas-fired capacity and operating costs would be increased substantially. Estimates of some of the more direct additional operating and carrying costs that would apply in 1985 without including the inflation adjustment factor are as follows:

	Billion per year
Fixed charges on scrubbers on all new coal burning power plants	$3.3
Additional operating costs to use and maintain scrubbers	1.7
Tax on utility oil consumption beginnings in 1983	1.2
Tax on utility gas consumption beginning in 1983	0.85

The various provisions of the bill and other legislation need correlation if we are to have a rational energy plan. These include the Title II tax provisions and the Title I "coal conversion" provisions, with basic tax and economic policy on one hand, and with clean air act, strip mining, and other environmental provisions on the other. H.R. 8444 recognizes in Title I that various conditions may result in exemptions from requirements to convert from oil or gas to coal for boiler fuel. Despite this, Title II imposes punitive taxes on these facilities where no other feasible fuel option exists. These taxes will increase the cost of electricity to consumers but will do little to promote conservation of oil and gas. Today's high cost of these fuels is already bringing about this phase-out, and no new base-load, petroleum fueled generation is now being planned. The proposed user taxes are not the rational way to have utilities phase out oil and gas as boiler fuels. A course of action that would be much more in the public interest would be to remove constraints against, and encourage construction of new coal and nuclear fueled generating facilities, rather than to promote uneconomic conversion or retirement of existing oil and gas fueled facilities.

We believe that the user tax will create regional inequities. These taxes would be collected from the customers of electric utilities in some areas of the country through increases in electric rates because of the type of fuel burned but would not be rebated in the same proportion as paid. The oil tax burden would fall disproportionately hard on electric customers in the Northeast, the Southeast and in California. The gas tax burden would hit the hardest on customers mainly in the Southeast and the Southwest. Similar inequities exist in the uneven manner in which the crude oil equalization tax is collected and redistributed.

Relative to the user tax, a House floor amendment deleted from the bill language providing an exempt use classification with regard to fuel burned in those new electric power plants granted exemption from the oil and gas prohibition requirements of the Energy Supply and Environmental Coordination Act of 1974, as amended by the National Energy Act (referred to as "ESECA"). The House Committee on Ways and Means did not think it would be appropriate to impose a tax on use of oil or gas in such exempt facilities, so under the Committee's bill any use of oil and gas in such facilities would be exempt from the tax for the duration of the exemption under ESECA. We strongly urge that the decision of the House tax writing committee be supported, the exemption be reinstated and fuel burned in existing plants subject to ESECA exemptions be included.

The tax provisions as now contained in H.R. 8444 will increase the taxes of an electric utility, and consequently increase the price of electricity to customers, even though the utility acts to implement the national energy policy by converting much of its electric generating capacity from the use of oil or gas as boiler fuel to the use of coal or some other alternative energy substance. This occurs because the bill denies the regular investment tax credit (presently 10 percent) for any qualified conversion investment which is used as a credit to offset the user tax. Thus, even where a utility's user taxes are fully offset by conversion expenditures, the cost of electricity to its customers will increase because of the loss of investment tax credits for otherwise fully qualifying property. This is grossly unfair; clearly the regular investment tax credit should be allowed and only the additional 10 percent energy credit should be denied in such situations. This also results in an inequity to the employees of such a utility whose ESOP benefits are denied or recaptured.

In summary, we strongly recommend that the equalization taxes and the user taxes be deleted from H.R. 8444.

Further, there follows additional recommendations, mostly of a technical nature, for the Committee's consideration.

ADDITIONAL PROPOSED AMENDMENTS TO H.R. 8444

1. Recapture of investment tax credits

The bill provides for recapture of investment tax credits for qualified investment where the investment is utilized to offset user taxes. An electric utility company may elect a credit against the user taxes of one dollar for each dollar of qualified investment, made after April 19, 1977, up to 100 percent of the company's liability for oil and natural gas user taxes. This election by an electric utility company may be made in 1984 for 1983 and subsequent tax years. Under the bill all investment tax credit taken on investment in alternative energy property in tax years 1977–1982 would be recaptured on the 1983 Federal income tax return. An amendment should be made so that there would be no recapture until the tax year that the investment is used to offset user taxes.

2. Recapture of employee benefits under ESOPS

The recapture discussed above would also have the effect of rescinding benefits to employees attributable to an ESOP. If an electric utility elects in 1984 to treat investment in alternative energy property as credits against the user taxes, the utility company's employees will suffer a rescission of their ESOP benefits measured by the 1 percent or 1½ percent ESOP credits attributable to such qualified investments. To avoid this unintended consequence to employees, the bill should be amended to clarify that neither the ESOP credits nor the regular credits would be recaptured based upon the user tax election.

3. Order of use of investment credits

H.R. 8444 provides for an additional ten percent investment credit on alternative energy property. This additional credit can be applied to offset up to 100 percent of the taxpayer's income tax liability. The allowance of a 100 percent offset will aid utilities, and other businesses, in installing energy property since many electric utilities and other taxpayers would not be helped if regular investment credit usage limitations applied.

The bill does not, however, specify whether the additional credit is to be applied before, after, or proportionately with the regular 10 percent credit and the ESOP credit. The order of utilization of the various credits may have substantial economic results to a taxpayer and therefore should be specified in the bill. Effectiveness of the new energy credit would be greatly enhanced if it is provided that the energy credit for a taxable year will be used only after the regular credit for the same year is exhausted.

A similar problem already exists in connection with the regular credit versus the ESOP credit. If the ESOP credit is elected for a year and there is a carryover from that year, a taxpayer does not know when the ESOP contribution must be made. It would be helpful if H.R. 8444 specified the order of use of the elements of the total investment tax credit.

4. Heating oil debate

The bill provides that persons who use oil for heating residences, hospitals, schools and churches will, in effect, be exempt from the payment of the crude oil equalization tax. Under this provision a large number of these users will be provided with lower cost oil for heating purposes than is generally available for other purposes. The bill fails to provide any relief from the crude oil equalization tax for the heating of residences, hospitals, schools and churches with electricity generated in oil fired power plants. The purchasers of electric power for heating should not be penalized any more by the equalization tax than their neighbors who utilize oil directly for heating purposes.

The bill should be amended to provide that where oil is used by a public utility to generate electricity, which is subsequently used for the heating of "exempt structures," that the purchasers of such electric power should receive rebates of the crude oil equalization tax comparable to those available to direct oil heating consumers.

The CHAIRMAN. The next witness is Mr. Floyd W. Lewis, president, Middle South Utilities, Inc., accompanied by Mr. William McCollam, Jr., president, New Orleans Public Service, Inc., Mr. Jack M. Wyatt, president, Louisiana Power & Light, and Mr. William Heaner, vice president, Gulf States Utilities Co.

We are very pleased to have you, Mr. Lewis, and also your very able associates. In my judgment, most people agree that you are doing a very fine job in the Middle South area and Louisiana is proud to have you represent them, in particular.

STATEMENT OF FLOYD W. LEWIS, PRESIDENT, MIDDLE SOUTH UTILITIES, INC., ACCOMPANIED BY WILLIAM McCOLLAM, JR., PRESIDENT, NEW ORLEANS PUBLIC SERVICE, INC., JACK M. WYATT, PRESIDENT, LOUISIANA POWER & LIGHT AND WILLIAM HEANER, VICE PRESIDENT, GULF STATES UTILITIES CO.

Mr. LEWIS. Thank you, Mr. Chairman. We are very appreciative of the opportunity to appear before the committee to talk about certain aspects of the President's energy proposal.

As you mentioned, Bill McCollam is chief executive of our New Orleans company; Jack Wyatt is chief executive of our Louisiana company and in our system we also have the Arkansas Power & Light, Arkansas-Missouri Power Co. and Mississippi Power & Light Co.

Altogether, they form the Middle South Utility System, and it is operated as an integrated electric system.

I would like, in opening to compliment the committee for the statements that I have seen reported in the press that had been made by various of you already this week about the need for greater emphasis on the supply side of the energy equation of the country.

We, in our system, based on what knowledge we have, certainly agree that our country is not an energy deficient area of the world, that the potential resources available in the shale oil, the dissolved methane of the Gulf region, coal, nuclear, that we have untold energy resources if we simply have the will to develop and make us of those resources.

I would like to use as the premise for our comments a statement made by Mr. Schlesinger before this committee, I believe on Monday of this week. He said, "Above all, the United States should solve its energy problems in a manner that is fair to all regions, sectors and income groups." We would like to talk about the question of fairness on a regional basis.

Our system is a system that was developed basically as a gas-fired system because that was the indigenous fuel in our part of the country. It was being flared, as you know—the powerplants provided a base use for the gas that was being wasted.

Up until about 1970, all of the units built in our system were gas-fired. In the early seventies, we added three units that can burn either oil or gas on a continuous basis. We have one nuclear plant in operation, five others under construction, the last of which would be scheduled for operation in 1984.

We have two coal-burning units now under construction in Arkansas, and many others planned.

The use of gas in our system was reduced by 31 percent from 1970 to 1976. The projection for use of gas as fuel on our system from now to 1986 is for a further 61 percent reduction.

This ties in with the numbers that Mr. Thompson was giving on the industry as a whole. We are now in a program of moving from 100 percent gas fuel as late as 1969 to a very small part of our fuel being gas by 1986. We are moving just as fast as we can to have all of our baseload generation nuclear and coal fueled.

A lot of the cutback in gas on our system has been as a result of Federal action. We had gas supplies contracted for at stated prices and with firm delivery, contracted, and as a consequence of action of the Federal Power Commission, that gas has been curtailed and our system, our customers in the Middle South System, of which there are 1,400,000 in round numbers, have paid, in the period of 1971–76, we calculate an additional $610 million because of having to replace gas that we had under contract that was not delivered because of FPC action, with fuel oil, or purchased energy from other sources.

Just to make it clear that we are not the favored few who do not have problems of supply, I would like to point out that the United Gas Pipeline Co., the major supplier of powerplant gas for our system, has more than twice as much curtailment on its system as the interstate pipeline company having the next, or second largest, amount of curtailment.

So already we are experiencing severe curtailment. It is not a case of those of us who happen to be located down in the Southwest getting all the gas we want and the rest of the country going wanting. The facts do not support that, at all.

I would point out in order to burn oil on a long-term basis, in these units designed to burn gas, we have already spent $180 million of capital to convert from gas to oil burning on our system and, in the process, we have lost capacity. We cannot get as much out of those units on oil and we have incurred tremendous problems of operation and maintenance costs escalating with the use of oil in those plants that were not originally designed to burn it.

As I mentioned, all of our plants now under construction and all planned for our system are either nuclear or coal fuel. We do not anticipate ever building a baseload unit that would use oil or natural gas as its fuel.

It was interesting to us in the Ways and Means markup hearings over in the House that Congressman Waggonner, of Louisiana, asked a question of the staff of the joint committee and the administration representatives there whether the tax on oil and gas used by utilities and the rebate that has been talked about some here this morning were meant to be incentives to phasing out oil and gas, as proposed by the President, or whether they were really revenue-raising proposals as written by the staff of the joint committee and the Treasury.

The reply was "both". In other words, as it was revised after getting to the Congress, it was intended to be an incentive, but also as a revenue-raising proposal, and we think that is the real problem with that particular tax.

This is the tax that would start out at $1.50 cents per barrel of fuel oil use in a utility boiler in 1983 and would continue at that level for oil use, and for gas would be 55 cents per million Btu's burned in 1983, 64 cents in 1984, and in 1985 and thereafter, 75 cents for a million Btu's.

The theory, as we understood it, was if you were moving to build up the kinds of generation other than fueled by oil and gas that tax was supposed to be a "wash". You could offset all of the tax on the user tax by qualifying expenditures for the right kinds of plants, which are those fueled with things other than petroluem and gas.

This got changed in the House, so that to qualify for a rebate you had to retire an existing oil and gas fueled generating plant or cut back its use to the point where it did not exceed 1,500 hours a year, so-called peaking use. That averages out as 4 hours a day.

If you did that, you could qualify for a rebate for the expenditure for the replacement kilowatt.

It was interesting to me that Mr. Schlesinger, in his appearance, made two statements about this program that I really do not understand. One of them was they were recommending an amendment to limit the rebate to only $125 per kilowatt of retired capacity. Mr. Thompson pointed out what the real cost of replacement of a kilowatt capacity really is. As I recall, he was using figures in the range of $600 or thereabouts for coal fueled up to $1,000 per kilowatt for nuclear.

So, Mr. Schlesinger is saying that they now want the Senate to further restrict the rebate so that you can only qualify for $125 of rebate for each kilowatt replaced, no matter what the cost of the replacement kilowatt might be.

That, to my mind, if I understand it—I am not sure that I do, but if I do—it is reducing the available rebates by a factor of maybe 75 percent. It might leave you with only 25 percent of the rebate that you thought that you could qualify for.

The other statement Mr. Schlesinger made was that a well-designed conversion program could result in rebates of all of the cost to the company of the program. In other words, you could offset all of the cost of getting rid of your gas and oil with other kinds of generation through the rebate program.

We did a study of what the cost to the customers—not to the utility companies, but the customers, the people who will ultimately bear these costs, what the cost to our customers would be for the period 1983 when the user taxes are first imposed through 1990, the date that Mr. Thompson referred to when practically all use of gas has to be terminated.

Our estimates show that the user tax during this period, 1983 to 1990, would amount to $1.6 million to the customers of the middle south system companies.

Our best estimate, forgetting Mr. Schlesinger's $125 limit which was not even in the picture then, but our best estimate on what the rebate would be during that period was from $400 million to $600 million. This means that the net cost to the customers of our system during the period 1983 through 1990 of the user tax, the penalty tax on the use of oil and gas in existing facilities, would be between $1 billion and $1.2 billion.

In addition, in trying to estimate what the impact on our system would be of the crude oil equalization tax which is imposed at the refinery level, as I understand it, we come up with a number in the range of about a half billion dollars for that same period, 1983 through 1990. Actually, that tax will start earlier than 1983 as now enacted in the House; there will be some costs in years prior to 1983, but we have not tried to estimate them. We are only looking at 1983 to 1990. Then trying to bring all of this down, the $2 billion total of the equalization tax, the penalty tax on oil and gas used by utilities, the rebate, which we estimate at $400 to $600 million on the previous basis, not Mr. Schlesinger's limited basis, and allocating it to our customers by States where the fuel would be used, we come up with a cost on average to residential customers in our system in the State of Louisiana of $200 per year in the period 1983 through 1990.

I would point out to you that the present total average electric utility bill for these same people in this system in the State of Louisiana ranges from $260 to $400. We are talking about here putting another $200 on top of that, so that the percentage increase is just astronomical.

Harkening back to Mr. Schlesinger's statement that these energy problems ought to be solved in a manner that is fair to regions, sectors of the economy and the income classes, I would like to point out that the impact by regions ranges in terms of increased costs that would be borne by the people in the various regions from this law from a 9-percent increase, and I believe it is the Midwest, where most all of your generation is now coal and nuclear, to our region which would have a 78-percent increase in cost as a consequence of the taxes in this plan.

Those are administration figures to which I have just made reference. I am sure that they are available to the committee.

The National Economic Research Associates has done a study which we attached to our formal statement—you will have it there—in which they try to measure what the results will be of a lot of different scenarios of imposing the kinds of taxes that are in the plan and the main conclusion of that is that just about everything that can be done, within reason, is being done and they term the plan as, in effect, regulatory or conversion overkill.

That is like saying I will pay any price for insurance. Hang the cost. I do not care what it costs the American people. We have got to have it done and we are willing to have them pay a price, without limit.

I think that you will want to have your staff certainly examine that. If you are interested in it, I am certain that Mr. Perl or one of the officers or members of the National Economic Research Associates will be pleased to discuss that study with your staff or come before the committee.

The General Accounting Office, the Comptroller General's report of July 5, 1977 had this to say. "It is reasonable to question whether it is, in fact, feasible to accelerate utility coal conversion in this region"—that is the south central states—"beyond what has already been planned."

Senator PACKWOOD. May I ask a question?

Are you being forced by the FEA to make these conversions that Mr. Thompson referred to?

Mr. LEWIS. No, sir, because we have no units on our system which are capable of conversion. Most of the 114 units that Mr. Thompson made reference to were units that either were initially coal-burning units that were then converted to oil for environmental and other reasons, or which were dual fuel units planned originally to be able to burn either coal or oil.

All of our units were planned to burn only gas, with the exception of the three units that I made reference to that we brought on line in the early 1970's.

Senator PACKWOOD. I used the term conversion wrong; you are talking about replacement. FEA is not asking you to replace those natural gas units with coal units.

Mr. LEWIS. They do not have authority, under existing law, as I appreciate it, to order you to replace. They can order you to convert any unit where it is technically and economically feasible to convert to coal.

Senator PACKWOOD. Since Mr. Thompson testified I had one of my aides call FEA and that is what they said; they cannot force the change, they can force conversion.

Mr. LEWIS. That is correct.

Senator PACKWOOD. To the extent that we have a lot of plants in this country that cannot convert, they are exempt?

Mr. LEWIS. That is correct.

Senator PACKWOOD. In the last paragraph of your statement, you asked to rewrite the bill to provide reliable incentives to go to the increase in coal. You say that there is some kind of a user tax, some kind of incentive that would cause a good many plants to change to coal that would not otherwise change. If they had the right incentive tax or otherwise——

Mr. LEWIS. No, sir, I am afraid we were not very clear in our statement.

It was our thought that the way to reduce oil and gas used in utility boilers is to remove the roadblocks, to ease the way, for the construction of baseload, new baseload, coal and nuclear units.

We do not really see it as being economic, under any kind of scenario that you might suppose, to tear down an existing boiler, have the plant out of operation for anywhere from months to several years while you build a brand new coal-fired boiler; this is what conversion is.

Senator PACKWOOD. When you talk, to provide viable incentive for moving to increase coal and nuclear use, you are not talking about economic incentives, you are talking about removing the roadblocks that would make the conversion easier?

Mr. LEWIS. Yes, sir. To make it possible to have enough coal to meet the needs of the Nation rather than putting additional roadblocks in the way.

Senator PACKWOOD. How many, percentagewise—or any other figure you can give me—are there in this country of these natural gas-burning plants that cannot be converted, not designed for conversion?

Mr. LEWIS. It is my impression, sir, that there were no plants that were designed solely for natural gas fuel which are convertible.

Senator PACKWOOD. How many are there in this country?

Mr. LEWIS. I do not have the number with me. It is available, but I do not have that particular number. It is a relatively small part of the total.

This is in megawatts. I do not have it in unit numbers. They vary all the way from small units of 100 megawatts to units of up to 500 and 600 megawatts.

There were 93,000 megawatts of steam electric generating capacity in the country in 1976 that were oil fired. Let me see, there is another figure. The gas-fired was 59,000 megawatts. I can get the number of units that make up those totals and submit that for the record. I just do not know how it is divided up.

[The following was subsequently supplied for the record:]

	Megawatts	Percent
Oil-fired capacity:		
Capable of being converted to burn coal without complete reconstruction of boilers boilers and fuel-handling equipment	20,000	21.5
Unable to be converted	73,000	78.5
Total	93,000	100.0
Gas-fired capacity:		
Capable of being converted to burn coal without complete reconstruction of boilers and fuel-handling equipment	2,000	3.3
Unable to be converted	57,000	96.7
Total	59,000	100.0

Note: The sources of statistical information available to us do not include the number of gene rating units which make up each of the megawatt capacity figures in the foregoing.

Senator PACKWOOD. Coming back to the premise of the administration that we have got to conserve oil and gas, I am not sure yet that their premise is right about the availability of oil and gas. Conceding it at the moment, and if the FEA cannot force this replacement because it is simply beyond their purview and cannot convert, it does become a very relevant statistic as to how much natural gas or oil could be saved by the forced conversion or forced changing.

It may not be worth it. We may not want to do it. It is a factor that is very relevant. If you could get it for me, I would appreciate it.

Mr. LEWIS. Yes, sir. I think we could come up with some numbers on that. I think it does boil down to the question then, is the price which would have to be borne by the American people, a fair and equitable one?

I would repeat the numbers—I am sure you got them from Mr. Thompson's testimony—in terms of the proportion of all the gas use in the country that the electric utilities will be using in 1986 is about 6 percent; only 6 percent of all of the gas use in the country in 1986 will be used by utilities, only 6 percent of it.

That will only account for 11.3 percent of our fuel. We are already moving on that.

What is left to work with is really relatively small in terms of the broad picture of the energy problems of this Nation.

Senator PACKWOOD. There is a fear that we are running out of oil. Some think it is going to be gone in 1985. That is the end of it, in that case. If that premise were true, any cost of conversion would be worth it as opposed to having no gas and oil.

I am not convinced, in the long run. I have looked over and over the USGS findings with their staff. I am not convinced in the long run that it would not be better to stay with oil and gas until we move

30 to 40, 50 to 60 years from now to solar and the cost of building our coal fields and slurry pipelines may not be worth the conversion cost.

Mr. LEWIS. I think that is a very good question and one that certainly should not be handled in an offhand way just in order to say we have got an energy program enacted. There ought to be some answers to the kinds of questions that you are raising.

As I indicated in the beginning, we are very strongly of the view that there are almost unlimited energy resource possibilities in the United States and we are not a deficient area.

A sentence which appears in one of the Mobil ads—some of you have read it, and I believe this particular one Senator Long shared with some of the Members of the Senate and there was a statement in there by Mobil that said something like, "If we are willing to put the required effort on the supply side of the equation we can avoid becoming an austere society."

I do not see any need for us to become an austere society.

Senator PACKWOOD. I think the chairman and Senator Talmadge and others have put forth the proposition we are not running out of energy. We have an energy crunch over the next 10 years because of bad planning and we run a tremendous risk, diplomatically, militarily, and economically because of imported oil that could have been avoided 20 years ago if we had started down the right path; we did not.

Over the next 10 years, we are in a terrible bind. That does not mean we are running out of energy. It means that it takes awhile to bring it online. There is nothing we can do in the next 3 years to drop our oil imports to zero or 5 million barrels a day, no mater what we do.

Mr. LEWIS. That is exactly right, sir.

As far as replacing oil and gas-fired kilowatts in 1983 when this user tax goes on, the only way they can do that is something that is with already under construction. As far as decisions made today to build something new to replace the oil and gas-fired plants by 1983, it is too late. The time has already passed. We should have made that decision some time ago.

So, another part of this plan that has been referred to already that I find totally unacceptable is the idea of saying that with respect to something that the Government finds you really cannot do—that is, convert to coal or nuclear by 1983—they are going to put a penalty tax on you for going ahead and burning what you can burn.

It is just beyond me. I cannot understand what kind of country we are becoming.

The CHAIRMAN. It seems to me that your argument is, if the Government tells you what it wants you to do and you do what the Government tells you it wants you to do, it has no business penalizing you just because you did it.

Now, in the alternative, the Government tells you that it would like for you to do something that cannot be done and it cannot be done, then there is no point in penalizing you for something the Government would be unable to do itself.

For example, we have, in this bill, a tax on gas guzzlers. I drive a gas guzzler. A lot of other people drive a gas guzzler. The Government got the idea of taxing gas guzzlers. We are not penalizing the people who already own gas guzzlers; we are saying that for the future we would like for you to buy some other automobile, and you should pay the tax if you buy the big automobile.

I think that I am probably going to continue to want to buy a big automobile to accommodate my own wife and my constituents who come with a bunch of bags to the airport. If I do, I will pay that tax. We are not penalizing somebody in the gas guzzler tax for something he has no choice over. It would seem to me that, if the Government tells you in the middle south, and Louisiana especially, what it wants you to do, and you do it, they should not penalize you anyway.

That reminds me of the story about the lion and the lamb. They were both drinking out of the same little stream, and the lion looked at the lamb and said, "lamb, I am going to have to eat you. You are muddying up my water."

And the lamb said, "sir, how could that possibly disturb you? I am drinking downstream from where you are drinking."

The lion thought about it for a moment too, and said, "I will eat you anyway."

Mr. LEWIS. We do feel like the lamb, sir.

The CHAIRMAN. That is what we are talking about. Implicit in this tax, if it makes you retire a lot of good equipment that still has useful life, is a waste of resources. We ought to be using these resources. It is simply capital in place, and it seems to me that we ought to be using our available capital to drill a lot more rapidly than we are doing even in the Louisiana area.

There is a lot of gas and a lot of oil that can still be produced to increase the supplies that we have. What I am reading and hearing from people in the business is the impediments that have been imposed on further exploration, most of them environmental. Even before the new law that we just passed goes into effect, there is about a 4-year delay from the time it is decided to drill in an area to try to provide some more gas until the time that the field is actually in place and the gas on its way to shore. I am told that the latest law might add another 20 months to that, so that would make about 6 years from the time that the decision is made to put an area up for lease until the time that it can be producing.

If we want more production, it seems to me that we ought to be thinking about shortening the exploration delays, just ilke we ought to be thinking about bringing on the geopressurized methane in the southern part of the country.

I personally think that geopressurized methane production will work and the witnesses who testified before our committee say they think it will work. I discussed it with Mr. Schlesinger. He says there will be technical problems. He thinks it will work. There will be technical problems. It will cost money to find out how to get around the problem. If that technology succeeds, everything that Mr. Schlesinger asks you to do about junking all your gas burners will be something he will ask you to reverse, is that not right?

Mr. LEWIS. Exactly, sir.

The CHAIRMAN. As I understand your principal point, if you are doing what the Government wants you to do, neither should you be penalized, nor should your customers who are powerless to defend themselves.

Mr. LEWIS. That is exactly right. In our system, with the kind of construction program that I mentioned earlier, we will be down to only 12-percent reserve capacity in the early 1980's as against our traditional planning number that has been 16 percent.

We do not have any leeway. We have got to keep these units available if we are going to keep the lights on.

As I mentioned, our use of gas by 1986 will be reduced by a further 61 percent from the amount used in 1976.

We are working as fast as we can to get on coal and nuclear. We feel if the Government decided, for reasons of its own, to retire perfectly good plants then the taxpayers of the country generally should provide the capital to make that conversion and retire those existing good plants, rather than pushing that on people who happen to have the misfortune of living in that part of the country that produces all the oil and gas for the Nation.

I do not think that you ought to penalize people because they happen to live in the areas that produce energy.

The CHAIRMAN. Basically, they are doing everything they can do. Part of our problem is that we want to produce more energy, but it takes begging for the right to do it, pleading with the Government to get out of the way and let us do it.

Mr. LEWIS. Exactly.

The CHAIRMAN. It is tough enough to be told that they will not let us produce the energy and now they are going to penalize us for things that we could do but they will not let us do. Then they order us to do something, and we do it, and they penalize us anyway. So it seems to me that is an unfair way for the government to do business with its own citizens.

Thank you very much.

[The prepared statement of Mr. Lewis follows. Oral testimony continues on p. 274.]

STATEMENT OF F. W. LEWIS, PRESIDENT OF MIDDLE SOUTH UTILITIES, INC.

My name is Floyd Lewis, I am President of Middle South Utilities, Inc. With me are William McCollam, Jr., President of New Orleans Public Service Inc., and Jack M. Wyatt, President of Louisiana Power & Light Co., two of our five operating subsidiary companies, the other three being Arkansas Power & Light Co., Arkansas-Missouri Power Co. and Mississippi Power & Light Co. There operating companies comprise the Middle South Utilities System and are operated as a single integrated electric system.

I would like to talk today about the impact of the President's and the House-passed tax and "coal conversion" programs on our System and its customers, and whether it is a fair and equitable way of achieving a phase out of oil and gas as boiler fuel for generating electricity.

I. MIDDLE SOUTH UTILITIES SYSTEM

The Middle South System serves over 1,400,000 electric customers in the states of Louisiana, Mississippi, Arkansas and a small part of Missouri. All major fossil fuel generating units in the System were designed to burn natural gas as their primary fuel from the days when we first contracted for gas that was being flared from oil wells our region, until about 1969, when evidence of the impending shortage of natural gas became apparent. While the System's generating units were historically designed to burn only natural gas on a continuous basis, to handle emergency situations involving loss of gas fuel for short periods of time, the boilers were equipped to burn fuel oil intermittently for very limited periods. We completed construction of three generating units in 1975 capable of burning oil or gas as a primary fuel. However, since the early 1970's, commitments for new generating facilities to be placed in service after 1975 have been based on having all future base load units use nuclear and coal as fuel; by 1967, we had contracted for our first nuclear unit.

Under orders of the Federal Power Commission, delivery of natural gas to Middle South powerplants by interstate pipelines already has been greatly curtailed, beginning in the early 1970's. The System's natural gas usage as a boiler fuel dropped by 31 percent in the period from 1970 to 1976, representing a total reduction estimated at 667 million MCF of boiler fuel gas for the 6-year period. Our present projections call for an additional 61 percent reduction in use of natural gas as a boiler fuel by the System between now and 1986. Concurrently, the System's oil usage increased from 975,120 barrels in 1970 to 25,130,000 barrels in 1976, and an estimated 36 million barrels in 1977. It is projected to range between 30 million and 40 million barrels per year in the 1980's.

The necessity of substituting fuel oil and purchased energy for curtailed natural gas (which was contracted for on a contract-price, firm-delivery basis, but not delivered) has increased the fuel costs to our customers by an estimated $610 million over the 1971–1976 period. These costs, together with associated boiler conversion costs, represent a burden already thrust upon the consumers in our service area by virtue of federal governmental action. At the same time, curtailments by United Gas Pipe Line Co., the interstate pipeline supplying the greater portion of the System's boiler fuel, have been nearly double those of the pipeline with the second largest curtailments (Schedule I, FPC Curtailment Report, November 1976).

The Middle South Utilities System operating companies have expended approximately $180 million to convert their major boilers served by interstate pipelines in order to permit burning oil for extended periods. None of these modifications were done with the contemplation of eventually converting to coal-firing; therefore, all of the modified facilities would have to be prematurely retired and replaced with new coal or nuclear facilities under the proposed legislation, at additional economic cost to our customers. Furthermore, the System companies have experienced greatly increased operating and maintenance problems and expense and loss of unit capacity as a consequence of the increased use of fuel oil in boilers not originally designed to burn oil on an extended basis.

It is anticipated that the Middle South Utilities System will consume about 36 million barrels of oil in 1977 (44 percent more than in 1976) to supplant the natural gas shortfall and meet our customers' energy requirements. Our customers are already bearing a very heavy financial burden as a result of shifting from cheaper local natural gas to higher-priced oil as a boiler fuel.

II. NATIONAL ENERGY PLAN

On top of these costs, our customers may now have to bear the taxes proposed by the President, and passed in far different form by the Ways and Means Committee and the House of Representatives. The intent of the President's program appeared to provide incentives to utilities using oil and gas to continue their move to coal and nuclear fuels. Our System has no new large base-load generating plants using oil and gas planned for construction in the future. All base load additions under construction now are planned to be coal- or nuclear-fueled. New coal and nuclear plants to be able to phase out existing oil and gas plants beginning in 1983 must already be under construction at this time. To enable us to complete the job now under way, we need faster nuclear licensing and construction programs and realistic environmental regulations and permit time frames to construct these replacement plants as well as those needed to meet our projected load growth; what we do not need are the burdensome new taxes contained in the House-passed legislation.

In the House Ways and Means mark up hearings, Congressman Waggonner of Louisiana asked the staff of the Joint Committee and Administration representatives whether the provisions on taxing utility oil and gas use and rebating part of the taxes were meant to be incentives to phasing out oil and gas as proposed by the President, or whether they were meant to be revenue-raising proposals as rewritten by the Staff of the Joint Committee and the Treasury. The reply was: "both;" and that is the problem with the legislation as it now exists before the Senate.

The President's bill contained a "coal conversion" regulatory program that was applicable to both industries and utilities, as well as a conversion incentive tax program. It appeared to allow utilities the time to phase down their oil and gas-fired generating facilities to peaking load use beginning in 1990 and to, in effect, exempt them from the tax on oil and gas use by allowing them to build up rebates against the tax beginning in 1979, so that they and their consumers would bear no tax burden as long as a construction program for non-oil-and-gas replacement boilers was continuing.

In addition to the rebate on the oil and gas use tax, utilities appeared to be entitled also to increased investment tax credits based on their construction programs under the proposal. This seemed equitable in that it did not require the customers of utilities with oil and gas generation facilities planned or built before the OPEC oil embargo to bear the heavy burden of a now-different national energy policy requiring the use of coal and nuclear fuels. It seemed to spread the burden of the construction programs for these fuel changes to the nation's taxpayers as a whole, although utility consumers would still have to pay the higher fuel prices resulting from the crude oil equalization tax.

When I testified before the House Ways and Means Committee on the tax aspects of the National Energy Plan on May 24, 1977, I dealt primarily with the failure of the President's bill to deal with the relationship between the tax provisions, the "coal conversion" regulatory provisions and the provisions of the pending Clean Air Act amendments that would require flue gas desulfurization systems (scrubbers) on all new coal plants, including those using low sulfur western coal. Our calculations of the cost of scrubbers (together with operating and maintaining them) to the nation's electric consumers by 1985 was an additional $5 billion per year. The House did not change these provisions of the Clean Air Act.

III. WAYS AND MEANS—HOUSE ACTION

However, the Ways and Means Committee changed an already questionable tax program into one that is a disaster for consumers in states where electricity is generated with oil and gas in plants built under previously existing national energy policies.' Apparently recognizing the problems of Los Angeles and New York City, the Ways and Means Committee exempted from the tax existing oil and gas generating plants that could not convert to coal for environmental reasons, but ignored those which could not convert to coal for technological or financial reasons. The rebate or credit against the oil and gas use tax was severely limited to tax-year construction expenditures which qualified for the credit only to the extent that old oil or gas-fired plants were retired to peaking use (1,500 hours per year, or about four hours per day). Recapture of the credit was required if use exceeded 2,000 hours.

In addition, the legislation was changed so that utilities were required to choose between the use tax credit and the higher investment tax credit on new plants, instead of being entitled to both. The oil and gas rebate or credit was made applicable only through 1990, although the regulatory program recognized the need to continue burning oil and some gas after that time, thus further penalizing electric consumers. Confusing rules on amortization, normalization and flow through of the tax and rebate were proposed in place of what had been understood was intended by the Administration to be a "wash" treatment of the tax and rebate.

The impact of the "National Energy Plan" as passed by the House, would be to require consumers in regions generating electricity with oil and gas to bear the cost of prematurely retiring to limited peakload use efficient oil and gas-fired electric plants with substantial remaining economic life. Consumers would be charged for both crude oil equalization tax and a penalizing oil or gas use tax, offset by a severely limited credit (based on qualifying "retired" and new generating facilities) that would amount to less than half of the tax due in the case of our consumers. Our preliminary calculation, by year, of the tax for the Middle South Utilities System customers, is as follows:

1983	$171,323,000
1984	207,404,000
1985	230,799,000
1986	172,992,000
1987	193,083,000
1988	192,744,000
1989	202,610,000
1990	214,475,000
Total	1,585,430,000

The total for this eight-year period of $1.6 billion would be offset by a credit of somewhere between $400 million and $600 million, leaving a tax liability of about $1 billion; the portion of this allocable to the customers of our Louisiana companies amounts to $200 per year for each home owner. This does not include the cost of the crude oil equalization tax which would start next year. While the amount of this tax is difficult to compute, assuming it to be an average $1.80 per barrel during the period of 1983 to 1990, it would add another $400 million to our cost of generating electricity, bringing the total tax burden to the Middle South's consumers to $2 billion over that period as a result of this legislation, less any credit against the oil and gas use tax. In addition, the equalization tax would be assessed against oil used for generating electricity in years prior to 1983 when the oil and gas use tax commences. This whole program is hardly "fair and equitable" to consumers in our region.

The Administration's consultants have conducted similar analyses of the impact of the proposed taxes on the Middle South System, which we have reviewed and commented upon. We have agreed to review any additional analyses, as well as the impact on our system of alternate programs that may be proposed for your consideration.

IV. CONCLUSIONS

We believe that the cost of abruptly changing our national energy policy to one based on coal and nuclear fuels for electricity should not be borne principally by consumers in the South and Southwest as would result under the House program. The crude oil equalization tax alone is probably too heavy a burden to impose on the consumers of our region, particularly when one considers that this tax would be rebated to people heating directly with home-heating oil, but not to those using heat pumps or other equipment powered by oil-generated electricity. When coupled with an additional penalty tax on the use of oil and gas in generating electricity, it is indeed a "disaster" for our region.

These tax and regulatory programs have been described as "conversion overkill," in an August 1977 National Economic Research Associates study, "The National Energy Plan and the Demand for and Economics of Coal Conversion," attached as Exhibit I.

Utilities are already moving as fast as they can to coal and nuclear fuels for electricity. This is recognized in the Comptroller General's July 25, 1977, report "An Evaluation of the National Energy Plan" at page 5.15 where it is stated: "In our study of U.S. coal development, we indicate that nearly all use of gas as a utility boiler fuel occurs in the South Central States, which account for nearly 90 percent of total U.S. gas production. In this area, gas reliance had been reduced to 87 percent by 1974, and a further 40 percent reduction by 1985 was already scheduled. In fact, by 1983 the base load generating capacity in this area is expected to be completely coal and nuclear. It is reasonable to question whether it is, in fact, feasible to accelerate utility coal conversion in this region beyond what has already been planned."

By 1985, electric utility use of natural gas as a boiler fuel will be reduced to 4 percent of the total national use, according to the National Electric Reliability Council, compared to industrial use of 50 percent. The crude oil equalization tax will be more than enough of an incentive to further decrease utility use of oil as fuel as rapidly as is possible.

In view of the on-going program to phase out oil and gas and the provisions of the regulatory program in S. 977 that apply to existing utility oil and gas boilers, we strongly urge that utility generating plants existing or under construction on April 20, 1977, be exempted from any taxes imposed on the use of oil and gas to generate electricity.

We would also point out that for many electric utilities in growth areas with large construction programs, additional investment tax credits by themselves do not provide much of an incentive for faster phasing out of oil and gas, since such utilities often cannot utilize all of the existing investment credit. The Middle South System is in such a posture. It instituted an investment credit Employee Stock Ownership Plan for its 10,000 employees for the year 1975 and we now find that we have insufficient earnings to fully utilize the credit for our employees for the year 1976 and, as a consequence, we are faced with the uncertainties of utilizing a carry-over of investment credit in future years.

Accordingly, we strongly urge you to: re-examine the hastily-passed House tax program; consider its discriminatory impacts on the customers of oil and gas burning electric utilities such as those in our region of the country; rewrite the bill to provide viable incentives for moving to increased coal and nuclear use; and provide a realistic time frame for phasing out existing oil and natural gas use without discriminatory costs to consumers in our region of the country.

THE NATIONAL ENERGY PLAN AND THE DEMAND FOR AND ECONOMICS OF ELECTRIC UTILITY COAL CONVERSION BY ALAN J. FISHBEIN AND LEWIS J. PERL, NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC., AUGUST 1977

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THE NATIONAL ENERGY PLAN AND THE DEMAND FOR AND ECONOMICS OF ELECTRIC UTILITY COAL CONVERSION

I. INTRODUCTION AND SUMMARY

The National Energy Plan (NEP) contains a complicated set of taxes, subsidies and directives designed to meet three explicit obectives.

1. To reduce the United States' dependence on foreign oil and its vulnerability to supply interruptions;
2. To weather the stringency in world oil supply that will be caused by limitations on productive capacities; and
3. To ensure that the nation develops renewable and essentially inexhaustible sources of energy for sustaining economic growth.

Since the United States resource base of coal is widely viewed as capable of sustaining economic growth for a greater number of years than can our other resources of fossil fuels, the NEP is designed to stimulate the substitution of coal for oil and gas.

The electric utility industry is thought to be a critical point of leverage for governmental action. One such set of policies contained in the NEP is designed to make the coal conversion or replacement of oil- and gas-fired steam generating units economically attractive. A second set of policies mandates the conversion of certain classes of oil- and gas-fired units. The purposes of this paper are to examine the economics of coal conversion under several variants of the NEP and to test the consistency of its conversion and replacement incentives with its targets for oil and gas consumption by the industry.

In order to accomplish these objectives, we have estimated the economic gains[1] associated with coal conversion and accelerated oil and gas replacement under a variety of assumptions as to the extent of taxes on oil and gas, the cost of coal, environmental restrictions on the burning of coal and Federal subsidization of conversion investments via tax credits. We have also adopted estimates of conversion capital costs adjusted to include the external social costs of converting an oil or gas unit to coal, such as the costs of scrubbers or low-sulfur coal, and the loss of reliability and generating efficiency when a unit is withdrawn from production while being converted. The estimates of economic gains and conversion costs are used to calculate the maximum amount of conversions and replacements that would be economic. This amount is compared with the estimated

[1] By "economic gains" we mean the reduction in the utility's total costs taking the fuel taxes and other economic conditions as given.

conversions and replacements required to meet the NEP oil and gas consumption targets for the utility industry. Our analysis required us to assume that electric utilities have great flexibility to accelerate or defer portions of their construction programs.

The conclusions of our analysis are:

1. Very little conversion would be necessary to achieve the oil and gas consumption objectives of the plan if the conservation and load management objectives of the NEP can be achieved, and if current construction plans of the industry are not otherwise impeded. This is because 40,000 to 70,000 megawatts of replacement capacity are already imbedded in the industry's construction program, and these coal and nuclear units will be used to replace an equivalent amount of oil and gas capacity by 1985. (See tables 2 and 3.)

2. If the impediments to an accelerated nuclear replacement option were removed, then it would be economic for virtually all oil and gas units to be either converted to coal or "prematurely" retired, without having to impose special user taxes on utility consumption of oil and gas. The price of coal and the stringency of environmental regulations on burning it will affect the relative proportions of conversions and replacements that would be economic, but not their total. Thus, if the 1985 target date can be relaxed, if nuclear licensing procedures are improved and if substantial increases in nuclear reactor orders do not singificantly worsen the economics of nuclear generation, then special taxes on utility use of oil and gas (or tax credits on conversion expenditures) are unnecessary. Such additional taxes and credits would slightly improve the economics of coal conversion relative to nuclear replacement but would not necessarily decrease the industry's consumption of oil and natural gas. (See tables 9, 10 and 11.)

3. Without an accelerated nuclear program, it would still be economic for the industry to convert or replace as much as 106 000 or as little as 13,000 megawatts without special user taxes on oil and gas; the amount of conversion that would be economic would depend on the price of coal and the environmental penalties on its use. Thus, if coal prices are $30 to $35 per ton and if environmental regulations on coal conversion are tough, the failure to expedite nuclear licensing procedures would mean that some additional tax on utility use of oil and gas (or additional subsidization of conversion and replacement investments) might be required to effect more than 13,000 megawatts of coal conversion and coal replacements. (See tables 8, 10 and 11.) At the same time, the increased economic attractiveness of the nuclear replacement option would provide increasing pressures for its acceleration. But with coal prices at $25 per ton and with no scrubbers required on converted units, it would be economic for the industry to convert as much as 106,000 megawatts of oil and gas capacity, even without the stimulus of special taxes on utility use of oil and gas.

4. The coal conversion program suggested in the NEP applies economic and regulatory pressures at the wrong places. The Plan will create undesirable incentives for the industry to reconfigure its production capacity at higher costs than are necessary. A less costly transition to greater utility use of coal and nuclear energy is achievable by removing some of the artificial incentives in the NEP and by deferring the target date to 1987. We find it potentially inefficient to implement any economic incentives or sanctions to expedite coal conversion without considering the effect of such policies on the industry's decision regarding replacement of oil and gas units with new coal or nuclear plants. The effort to create incentives and regulations designed to move the industry off oil and gas could more properly be aimed at resolving the contradictions in energy and environmental policies regarding the use of coal and nuclear power by the electric utilities. The coal conversion program could thereby be simplified immensely, saving regulatory and administrative costs as well.

5. We also find that the incentives in the coal conversion program are generally inconsistent with the targets for utility consumption of oil and gas: they amount to conversion overkill. Should the need arise, simpler and more direct subsidization policies can be formulated.

6. The conclusions of this study are subject to the following qualifications:

a. Oil and gas taxes imposed to encourage conversions will have a geographically uneven impact on consumers and utilities because the economic costs and benefits of conversion will vary considerably among regions. While some of these regional considerations have been incorporated crudely into our analysis, their ultimate inclusion requires more detailed focus on individual utilities.

b. For many individual plants, conversion may be infeasible or uneconomic, and the average conversion costs in this analysis should be regarded as no more than illustrative.

c. If regulatory commissions do not allow utilities to earn a return on the undepreciated balance of oil and gas units which have been replaced, oil and gas savings from replacement are likely to be deferred.

d. For utilities which will not have operating incomes large enough to allow them the full benefits of the current level of tax credits, additional investment tax credits will provide no incentive to either convert or replace.

The organization of this paper is as follows. In the next section we review the aspects of the NEP which will affect the decisions of electric utilities to convert oil and gas units to coal or to retire such units early. In the third section we calculate the amount of conversions and replacements required to meet the NEP overall targets for electric utility fuel use, given various assumptions about electricity demand, construction budgets and the reliability of new baseload units. In the fourth section we discuss the general economics of the electric utility planner's decision to convert, retire or maintain an old oil or gas unit, and we then examine in detail how the NEP taxes, subsidies and energy prices change the economics of such decisions. In this section we also examine the estimates of the investment costs for coal conversion, including the internalized costs of short-run reliability losses and fuel substitution costs, and estimate the level of oil and gas conversions and replacements implied by the economic incentives of the NEP. In the fifth section we discuss the compatibility of the conversions and replacements made economic by the NEP with the conversions and replacements needed to meet the targets of the NEP. In the sixth section we examine the ability of the coal mining industry to serve the conversion demands implied by the NEP. In the concluding section we comment on the consistency of the NEP's fuel consumption targets, coal conversion requirements, and tax and other incentives. In addition, the concluding section details several policy alternatives to the NEP as proposed.

II. THE NATIONAL ENERGY PLAN AND THE CONVERSION AND REPLACEMENT DECISIONS

The NEP contains five policies designed to expedite coal conversion by electric utilities:

1. Through a combination of price ceiling increases and taxes on old oil, the price of oil faced by the utilities would rise to the 1977 world oil price of about $13.50 per barrel by 1980.
2. The price of gas fixed by the utilities would rise to about the equivalent Btu price of oil or about $2.25 per thousand cubic feet by 1978.
3. A special tax on the use of petroleum by utilities will raise the price they face for this fuel by another $1.50 per barrel by 1983 to about $15 per barrel.
4. A special series of taxes on the use of natural gas by utilities will raise the price they face for this fuel from 1983 to 1988 so that their cost of gas would equal the cost of the Btu equivalent of distillate oil (before the special tax on utility use of petroleum products). This would make the price of natural gas to the utilities an equivalent Btu price of $18 per barrel (or $3.30 per Mcf) by 1988.
5. The electric utilities will be eligible at their election for an investment tax credit equal to an additional 10 percent (they already receive a 10 percent regular investment tax credit) on their conversion expenditures, or for a rebate on any natural gas or petroleum taxes paid up to the amount they have actually incurred.

These policies all tend to increase the operating cost differential between two equivalently depreciated oil or gas and coal units. They also tend to decrease the private capital cost of a conversion unit. In addition to these incentives, the NEP also affects the coal conversion decision with a series of mandates and prohibitions. Four specific kinds of regulatory policies are discussed in the Detailed Fact Sheet issued on the NEP:

1. Electric utilities will be prohibited from burning natural gas or petroleum in new boilers with only limited environmental and economic exceptions.
2. The NEP will prohibit existing facilities with a coal-burning capability from burning gas or oil. This will be regulated by classes of plants or on a case-by-case basis. With limited exceptions, no utility will be permitted to burn natural gas after 1990.

3. The NEP will require utilities to obtain federal approval in order to shift a plant from burning coal to burning oil or natural gas. A similar permit will be required of utilities wanting to shift from natural gas to petroleum.

4. The NEP will allow any utility prohibited from using natural gas to sell its contract to purchase gas at a price that would provide adequate compensation.

The legislation is written in such a way that it is difficult a priori to judge how stringent these mandates really could be. A recent article in The Wall Street Journal[1] suggests that the whole state of California and New York City will be exempted from having to use more coal. Without knowing how binding the mandates are, it is impossible to internalize with any rigor their impact on the demand for coal conversion. The most we can say is that such prohibitions increase the rental cost of unconverted old oil and gas units. Gas units which are not retired prior to 1990 would have to shut down except for peaking circumstances with the effect that a utility's generating plant expansion schedule might be moved up one or several years. Changing the schedule of a long-run plant expansion program is associated with positive economic costs.[2] When we discuss the general economics of converting oil and gas units to coal in the next section, we will not attempt to quantify the effect of regulated mandates on the cost of maintaining an old unit.

III. THE NATIONAL ENERGY PLAN AND THE NEED FOR COAL CONVERSION

The primary objective of the NEP as it affects the electric utility industry is to reduce the industry's reliance on oil and gas for boiler fuel. Consumption of oil without the Plan is projected at 2 million barrels of oil per day in 1985 and is to be reduced to 1.3 million barrels of oil per day with the Plan. Consumption of gas is projected at 0.9 million barrels of oil equivalent per day without the Plan and is to be reduced to 0.5 million barrels of oil equivalent per day with the Plan. These targets are to be accomplished by a combination of policies designed to encourage conservation in the use of electricity and to promote conversion of existing oil and gas plants to the use of coal, and by a set of as yet unformulated policies designed to reduce impediments to the construction of new coal-fired and light water reactor power plants.

One means for evaluating the conversion requirements of the Carter program is to estimate the level of industry oil and gas consumption under alternative assumptions regarding the effectiveness of Carter's programs for encouraging conservation and the construction of new coal- and nuclear-fired plants. Using these data, it is then possible to determine conversions and replacements required to meet the NEP's oil and gas targets.

Table 1 describes estimated consumption of oil and gas by the electric utility industry in 1985 under two alternative assumptions as to the total growth in electric consumption and under six assumptions as to the new plant capacity additions achieved by the industry over the period 1975 to 1985, and their capacity factors.

The two growth rates considered—4.7 percent per year and 5.25 percent per year—represent the implicit projections of the Carter Administration with and without the Plan, and the difference between these two growth rates may be viewed as the reductions in the rate of growth of electricity consumption which the Carter Administration projects can be achieved through the mandated and price-related conservation policies.

The basic planned additions scenario (Scenario 1 in the table) takes as given the Federal Energy Administration's (FEA) projections of planned additions of coal and nuclear plants as of May 1977. These planned additions reflect utility investments in capacity to meet load growth and to retire and replace inefficient baseload units. In this projection, both new coal and new nuclear plants are assumed to operate at a 60 percent capacity factor. The variations in this scenario which were considered include: lowering the capacity factor of new coal and nuclear additions to 50 percent (Case 2); raising the capacity factor of new coal plants to 65 percent while leaving the capacity factor of nuclear plants at 60 percent (Case 3); leaving capacity factors at 60 percent but increasing coal

[1] Les Gapay, "Increasing Use of Coal As President Proposes Faces Myriad Problems," The Wall Street Journal, June 9, 1977.

[2] See NERA paper, "A Framework For Marginal Cost-Based Time-Differentiated Pricing in the United States," Appendix C, 1977.

additions by 10 percent above the current FEA projections (Case 4); leaving capacity factors at 60 percent but reducing nuclear additions by 10 percent (Case 5) and 20 percent (Case 6). In projecting oil and gas consumption, the capacity factors of new plants are as stated in the scenarios, the capacity factors of old coal-fired plants are 50 percent, the capacity factor of hydro is assumed to be maintained at its historic average and oil and gas generation are assumed to meet residual demands. There are no oil and gas conversions in any of the scenarios examined.

As can be seen from the table, in most of the cases considered oil and gas consumption will exceed the targets laid out in the Carter Plan for 1985. There are, however, two significant exceptions. First, if the conservation targets of the Carter Plan can be achieved and new coal-fired additions achieve a capacity factor of 65 percent by 1985 or if total coal additions are increased by 10 percent, oil and gas consumption would be at or below the targets without any conversions. Generally speaking, moreover, if the Carter Energy Program's conservation objectives are achieved, oil and gas consumption by the industry is only modestly above the NEP's targets even without conversions. However, even here there are two significant exceptions. If the capacity factor of new coal- and nuclear-fired units averages 50 percent instead of 60 percent, or if currently planned nuclear additions are decreased by as much as 20 percent, oil and gas consumption will be nearly twice the targets. More significantly, if the conservation targets which are implicit in the NEP cannot be achieved, then the industry's oil and gas consumption in the absence of conversions is in all cases in excess of the NEP's targets, and in most cases the excess is quite considerable.

Table 2 estimates the oil and gas conversions which are required to bring the industry's oil and gas consumption in line with the targets of the Carter Program under each of the scenarios considered. In making these calculations of megawatts converted, it was assumed that converted units would be operated at an average capacity factor of 50 percent. As is evident from the table, in the base case considered—Case 1—assuming that the conservation targets of the NEP are achieved, only 16,000 megawatts of oil conversions and 1,600 megawatts of gas conversion would be required. In both cases, these are sligthly below the industry's estimates of the capacity which can be converted (see Table 5) without total boiler reconstruction.

Even if the conservation targets are achieved, there are substantial variations in the magnitude of conversions which would be mandated by the targets of the NEP depending upon the capacity factors of new additions and the level of new additions. Under the most optimistic assumptions, no conversions would be required and under the least optimistic assumptions 46,000 megawatts of oil-fired capacity and 26,000 megawatts of gas-fired capacity would have to be converted.

If the conservation targets of the NEP cannot be achieved, the picture is quite different. Here, even in the base case, 32,000 megawatts of oil-fired capacity and 17,000 megawatts of gas-fired capacity would have to be converted in order to achieve the targets of the NEP. Moreover, under the variations in capacity additions and capacity factors considered, oil conversions range from a low of 17,000 to a high of 65,000 while gas conversions range from a low of 1,700 to a high of 41,000 megawatts.

The data in Table 2 understate the extent of the industry's efforts to conserve oil and gas since in each case they exclude new oil and gas units which are being added to replace existing oil and gas units. In this context, replacement is defined as capacity added in excess of that needed to meet load growth.

Table 3 shows the sum of replacements and conversions required to meet the NEP utility fuel consumption targets in each of the six supply scenarios explored in tables 1 and 2. The variation in growth rates explored in tables 1 and 2 affects the balance between conversion and replacement but not their sum. Consequently, the estimates in Table 3 apply for either of the growth rates considered above. Under the most plausible set of assumptions—Case 1—about 88,000 megawatts of oil and gas capacity would be either converted or retired prematurely and replaced with baseload coal or nuclear units. Under the least favorable set of assumptions, this figure could baloon to 143,902 megawatts.

Three conclusions emerge from Tables 2 and 3. First, if the other objectives of the Carter Program can be achieved, quite limited amounts of conversions of oil- and gas-fired capacity would be necessary to achieve the oil and gas targets of the Plan. These limited conversions reflect the substantial extent of replacements which are implicit in each of the projected construction programs

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examined. Second, required conversions are quite sensitive to the success of the other objectives of the Plan, particularly its conservation and load management objectives and its stated objective of removing impediments to the construction of new coal- and nuclear-fired capacity. Third, under the worst scenarios considered, perhaps two-thirds of all oil-fired capacity and 80 percent of all gas-fired capacity would require conversion in order to meet the targets of the NEP.

At this point we have described the conversions and replacements in the Plan and the conversion and replacement requirements implied by the NEP fuel consumption targets. The likelihood that these conversions and replacements will, in fact, take place depends in part on the economic gains from converting or replacing existing oil and gas capacity. Estimates of the extent to which conversion and replacement are economic are derived in Section IV, below.

IV. THE ECONOMICS OF COAL CONVERSION

In this section we assess the extent to which the taxes and investment tax credit provisions of the NEP provide adequate economic incentives for conversion and replacement of oil and gas plants. In evaluating these incentives, we have assumed that utilities have three options in dealing with any existing oil and gas unit: they can maintain the old unit as it is for a finite time period; they can convert the old unit to coal and run it like an intermediate unit for an equally finite period; or they can retire the unit early and replace it with a newly constructed coal or nuclear plant. Conversion and replacement impose certain capital costs but also permit the substitution of lower cost coal (and in the case of replacement, nuclear fuel) for oil and gas. The economic attractiveness of the trade-off depends upon the magnitude of the capital costs of conversion or replacement and the fuel cost savings associated with these options. In this analysis, it is assumed that utilities will find conversion economically attractive if and only if the present worth of the fuel savings, net of the conversion investment cost, is positive and greater than the present worth of the net savings associated with retiring the unit prematurely and replacing it with a new unit. If the present value of the net savings from retirement and replacement are positive and greater than the savings from coversion, replacement will be the preferred option. Finally, if the present value of the net savings from conversion and replacement are both negative, the utility will choose to do nothing.

In viewing conversions and replacements in this way we have explicitly ignored a variety of constraints which may require uneconomic conversions or prevent the utilities from making conversions which are economic. In particular, we have made no allowance for capital constraints which may limit the amount of conversions and replacements which utilities can finance in any specified time frame. We have also not taken account of environmental constraints or manpower and equipment limits which may also slow down or curtail conversion and replacement. By the same token, we have ignored any proposed legislation which might compel particular plants to convert. Finally, no account has been taken of the effect of regulatory policy which, by preventing utilities from earning a fair return on prematurely retired units, might discourage replacements even where they are economic.

Estimating the extent to which conversions or replacements are economically attractive requires estimating the capital costs of conversion, the capital costs of replacement and the operating cost savings from each of these alternatives. Of these, our information is least satisfactory regarding conversion costs. Consequently, in this analysis we first estimate the maximum investment in conversion which might be economically justified. This depends on fuel costs, the capital costs of replacement and the capacity factor of new and converted units, but not on the actual capital costs of conversion. If at a later date conversion cost estimates are revised, or if others disagree with our conversion cost estimates, these estimates of maximum investments in conversion can, nevertheless, be used to assess the extent of conversion incentive.

In the second subsection of this analysis, we do present estimates of conversion capital costs for oil and gas units. These estimates reflect studies reported by Edison Electric Institute (EEI), supplemented by NERA's estimates of reliability and fuel costs during the period in which units are converted or reconstructed. In the third subsection, actual conversion cost estimates are compared with estimates of the maximum conversion investment which is economically justified in order to determine the extent to which conversions are justified under alternative versions of the NEP at alternative coal prices and environmental scenarios.

A. Maximum Conversion Investments

The oil and gas prices used in this analysis reflect two scenarios regarding the NEP: a simplified case in which the prices reflect the wellhead taxes in the NEP, and a more complete plan in which prices reflect the well-head taxes, the special taxes on utility consumption of oil and gas, and the additional tax credit on conversion investments. Oil prices are assumed to be $13.50 per barrel in the simplified case and $15 with all taxes included in the Full Plan. Gas prices are $2.25 per Mcf in the Simple Plan and $3.30 per Mcf in the Full Plan. For plants with less than 10 years of book life remaining, the price assumed for natural gas under the Full Plan is $3 per Mcf, reflecting the gradual buildup of the user taxes from 1983 to 1988.

For each of these policy scenarios, we consider three scenarios regarding coal prices and environmental policy. In the first case, delivered coal prices average $25 per ton and scrubbers are required on new, but not converted, units. In the second case, coal prices average $30 pre ton and scrubbers are required on converted units. In the final case, $35 coal prices and scrubbers on converted units are assumed.

All costs in this analysis are expressed in constant 1977 dollars. The constant dollar discount rate assumed in calculations of present worth cost is 10 percent (on a pre-tax basis) which is equivalent to a 15 percent current dollar discount rate adjusted for 5 percent inflation.

All old units are assumed to have 11,000 Btu per kilowatt-hour heat rates; new coal units are assumed to have heat rates of 9,000 Btu per kilowatt-hour. Scrubbers, if required, add 3.4 mills per kilowatt-hour in fuel, operation and maintenance penalties to both new and converted coal running costs. The capital cost of a new coal unit with a scrubber is assumed to be $600 per kilowatt, and the parallel cost for a nuclear plant is $800 per kilowatt. The levelized fuel cost of the nuclear unit is always assumed to be 8 mills per kilowatt-hour in 1977 dollars.

There is one further set of assumptions required. We would expect the capacity factors of unconverted oil or gas plants, coal converted plants, and new baseload coal or nuclear units to be quite different. The current construction program of the industry suggests that old oil and gas units will be operated at relatively low capacity factors by 1985. Compared to nuclear and recent vintage coal plants, the operating costs of these plants will be too high for the individual utilities to rely upon them for baseload demands. But if these units were to be converted to coal, their lower operating costs would change their place in the merit ordering for the plant dispatch, subsequently raising the capacity factors of the converted units relative to those associated with their unconverted state. Under the Carter Plan, with electricity sales growth at 4.7 percent per year, the capacity factors of unconverted old oil and gas units may be as low as 10 to 20 percent. We will assume that old oil units with more than 15 years of useful life remaining will be run at 50 percent capacity factors when converted; units with 15 years or less of useful life will be assumed to run at 40 percent capacity factors. New coal and nuclear plants that could be used to retire old oil or gas units are assumed to have levelized capacity factors of 60 percent.

In some cases, the limit on conversion expenditures is set by the fuel savings from conversion, in which case the alternative to conversion is the continued operation of the unit. In other cases, the limit on conversion is set by the net savings from replacement with a new coal or nuclear unit, in which case replacement is the course to be followed if conversion proves uneconomic.

Maximum investments in coal conversion are presented on a per kilowat basis in tables 4 and 5. In table 4, we examine maximum conversion expenditures when the new coal units provide the only means for replacement and early retirement of oil and gas plants. These maximum investments vary directly with the remaining lifetime of the plants under scrutiny. Under the Simple Plan, at coal prices of $25 per ton and no mandated scrubbers, these expenditures range from $169.73 per kilowatt for a plant with five years of reamining life to $527.59 per kilowatt for a plant with 30 years of remaining life. At a $30 coal price and scrubbers on converted units the range is constrained to $82.65 to $256.91 per kilowatt. If coal prices are as high as $35 per ton and scrubbers are required on converted units, the range is cut to $45.75 to $142.22 per kilowatt

Under the simplified NEP, the early retirement and replacement option never binds the maximum private investment in coal conversion. Consequently, if the investment required for conversion exceeds these maxima, the alternative would be to do nothing.

With the Full NEP, maximum conversion investments are substantially increased. At $25 coal prices, maximum conversion investments for oil plants under the Full Plan range from $234 to $728 per kilowatt. This is 38 percent in excess of maximum investments under the Simple Plan. For gas plants, the Full Plan increases investments by 72 percent. The effect of the Full Plan is even greater at higher coal prices. At $30 coal prices and scrubbers on converted units the Full Plan increases maximum conversion expenditures by 65 percent for oil plants and 140 percent for gas plants. At $35 coal prices and scrubbers on converted units the Full Plan increases maximum investment by 107 percent for oil plants and 300 percent for gas plants. With the Full NEP, retirement and coal replacement is the alternative to conversion for gas for all the cases examined and for oil as long as coal costs less than $35 per ton. Consequently, where conversion expenditures exceed these maxima, retirement and coal replacement will be the desired alternative for oil and gas plants in the majority of circumstances.

As is indicated in table 5, at moderate to high coal prices, maximum conversion expenditures are reduced substantially if nuclear replacement is a viable option. Under the Simple Plan, at $25 coal prices and no scrubbers required on converted units, the conversion option is limited by the alternative of doing nothing and, therefore, the conversion investment is unaffected by the availability of the nuclear alternative. With coal prices of $30 per ton and scrubbers on converted units, however, the nuclear replacements limit conversion expenditure for an oil or gas plant to a maximum of $209.42 per kilowatt (18 percent less than maximum conversion investment in the absence of the nuclear alternative) and at $35 per ton of coal, maximum conversion expenditures are $71.79 per ton (50 percent of the maximum in the absence of the nuclear alternative).

Once nuclear replacement is recognized as a viable option, the taxes and credits imposed under the Full Plan have little effect on maximum conversion investments. At $25 coal prices, maximum conversion increases investments from $528 per kilowatt under the Simple Plan to $601 per kilowatt under the Full Plan, an increase of only 14 percent. At $35 coal prices, maximum conversion investments are increased from $72 per kilowatt in the Simple Plan to $81 per kilowatt under the Full Plan.

B. Costs of Conversion

If the capital costs of conversion are known, the data in Tables 4 and 5 can be used to estimate the extent of economically justified conversions. The purpose of this section is to summarize briefly the available information on the average conversion costs. Estimates of the capital costs of conversion were reconstructed from those contained in an EEI report and its original sources.[1] To these we have added allowances for reliability losses and energy costs during replacement. The EEI report and its sources are also used to disaggregate the existing stock of oil and gas plants into conversion cost categories.

Estimates of the capital costs of coal conversion are given in Table 6. These cost estimates for oil and gas units are two-tiered. About 18 percent of all oil and 4.4 percent of gas capacity in 1975 are "convertible"—meaning they were either designed to burn both coal and oil or coal and gas originally, or were once coal units that were converted to burn oil or gas because of environmental mandates. A PEDCo Environmental Study puts the base costs of converting these units at about $10 per kilowatt for oil plants and roughly double that for gas units (in 1977 dollars). EEI estimates costs of $80 per kilowatt which include these base costs and an allowance for the environmental costs of conversion as well. The remaining oil plants would require boiler reconstruction, the cost of which is estimated at $250 per kilowatt without environmental controls and $325 per kilowatt with these controls. To burn coal most gas plants would require boiler reconstruction. For these plants the base cost of gas reconstruction has been broken down by unit size. (Apparently there are significant economies of scale

[1] T. Burbank, "The Phasing Out of Oil and Gas Used for Boiler Fuel: Constraints and Incentives," Edison Electric Institute, March 7, 1977, p. 12.

in oil and gas conversion.) The base costs are estimated to vary from $407.37 per kilowatt for units of 700 megawatts or greater to $566.50 per kilowatt for units of 200 megawatts or smaller. Environmental control costs for such units may also exhibit scale economies, and we have elected to use the estimates on such costs from the sources cited. Gas reconstruction base costs with scrubbers for reconstructible plants range from $476 to $712 per kilowatt.

These capital costs do not reflect a number of other social costs associated with conversion. During the conversion process the unit being converted would have to be shut down. The effect would be to reduce reserve margins and system reliability during the conversion period. Where the extent of conversion is limited and reserve margins are substantial, the extent of reduced reliability may be quite limited. With substantial conversion and limited reserve margins, however, cost might be substantial. Reductions in reserve margin reliability could be averted by advancing the new construction program of the utilities. Assuming a one-year outage for conversion or reconstruction, the maximum cost of maintaining reliability would be the annual rental cost of a peaking turbine which we have estimated at $18.73 per kilowatt. This assumes a 25-year life and a cost of $170 per kilowatt for these turbines. The costs of reduced reserve margins may be substantially less since many areas currently have substantial reserves. Thus we have assumed a range of reliability costs from zero to $18.73 per kilowatt.

During the period of conversion, energy otherwise produced by the converted unit would be supplied from other higher cost units on the system. At worst, these units would have the operating costs of combustion turbines which would exceed the operating costs of typical oil and gas units by 8.0 mills per kilowatt-hour. At an assumed 25 percent capacity factor for converted units, this cost differential would be $19.05 per kilowatt of conversion. Of course, operating costs for substitute units might be substantially lower. For the lower limit, we assumed that substitute units had operating costs averaging 1.0 mills per kilowatt-hour above those of the converted units. This produced the substitution costs during conversion of $2.19 per kilowatt.

The base investment, environmental, reliability and substitute running costs have been integrated into maximum, minimum and most probable estimates of conversion investment costs on a per-kilowatt basis and are shown in Table 6. Maximum estimates assume maximum scrubber, reliability and substitution costs. Minimum estimates assume no reliability or scrubber costs and minimum substitution costs. The most likely estimate of conversion investment costs reflects the authors' judgments about scrubber, reliability and substitution costs based on where the potentially convertible plants are located. The most likely estimates on convertible units are $74.30 and $95.78 per kilowatt for oil and gas respectively. For reconstruction, the most likely estimate for oil units is $313.64 per kilowatt, and the range for natural gas conversion is $479.65 to $677.20 per kilowatt. Despite their apparent precision, these estimates should be interpreted with caution since they reflect base conversion capital costs which were, of necessity, only rough estimates.

C. Extent of economic conversion

Using estimates of maximum conversion investments in Tables 4 and 5, estimated conversion costs in Table 6, and the projected age distribution of oil and gas plants in Table 7, we can determine the extent of conversions which would be economically attractive under alternative NEP scenarios, coal prices, environmental constraints and alternative views as to the availability of the nuclear option.

In interpreting these estimates, it is important to note that the base conversion costs assumed in this analysis are average per-kilowatt estimates. The averages may or may not be associated with the conversion cost for any particular plant. Therefore, care must be exercised in using these costs to infer maximum conversion quantities. Actual conversions will be based on marginal costs and benefits, not on average costs or benefits. Suppose, for example, the maximum expenditures on coal conversion for a particular type and age of plant is $200 per kilowatt. Assume that there are 100 kilowatts of this type of plant which may be converted for an average cost of $200 per kilowatt, but where the average represents 50 kilowatts with conversion costs of $100 per kilowatt and 50 kilowatts with conversion costs of $300 per kilowatt. The use of the average conversion cost estimates will cause us to overstate by 100 percent the extent of conversions which would be economic at a fuel savings of $200 per kilowatt. In this example, the use of averages caused us to overstate the impact of conversion in our answer, but it would also be possible to understate conversion for the same reason.

Estimates of the extent of economic conversion are presented in Tables 8 and 9. Table 8 contains the maximum economic conversion estimates, assuming that replacement with nuclear is not a viable option. Under the Simple Plan, with coal at $25 per ton (and assuming that no scrubbers are required on converted units), the industry will find it efficient to convert all (20,874 megawatts) of its convertible plants, 84 percent (69,000 megawatts) of its reconstructible oil plants and 33 percent (15,100 megawatts) of its reconstructible gas plants. A total of about 105,000 megawatts of oil and gas capacity might be economically convertible under these assumptions. On the other hand, assuming that coal costs $30 per ton and scrubbers are required on all converted units, then under the Simple Plan 90 percent of the convertible oil and gas plants could be efficiently converted to coal, but no reconstruction would be done. At coal costs of $35 per ton and scrubbers on converted plants, only 12,000 megawatts of oil capacity and 1,200 megawatts of gas capacity would be economically convertible.

The Full NEP increases the extent of coal conversion in each case, but the most substantial impact occurs in the intermediate coal case (coal prices of $30 and scrubbers on converted units). In this case, the Full Plan increases the extent of conversion from 19,100 to 70,874 megawatts, an increase of nearly 52,000 megawatts. At lower coal prices and no scrubbers required on converted units, substantial conversion occurs without the Full Plan, and the Full Plan only increases conversion by 35,000 megawatts. At higher coal prices ($35 per ton and scrubbers) the extent of conversion is quite limited without the Full Plan, but the inclusion of the Full Plan only increases conversions by 7,200 megawatts to 20,411 megawatts. Thus at low coal prices the amount of conversion is substantial even with the Simple Plan, and the Full Plan has only limited impact; at high coal prices limited conversion occurs with or without the Plan.

This picture is substantially reinforced when we consider the extent of conversions when nuclear replacement is a viable option. These estimates are contained in Table 9. Under the Simple Plan, at either $25 coal prices or $30 prices and scrubbers on converted units the extent of conversions is unaffected by nuclear replacement. At the $35 coal price there would be no conversions if nuclear replacement were a viable option.

With the option of nuclear replacements, the effect of the Full Plan is circumscribed. At a $25 coal price, the Full Plan increases conversions by 15,400 megawatts, but conversions in this case are already substantial without the Plan. In the other two cases examined, once we allow for the nuclear option the Plan has no effect on the extent of conversion which would be economic.

The extent of economic conversion is of course interesting in and of itself. However, if the objectives of the NEP are to save oil and gas one must also consider replacements. Table 10 presents estimates of the net present worth of the economic gains achieved from accelerated coal or nuclear replacement of oil and gas units with and without the user taxes. A number of observations emerge from Table 10. First, it is clear that without the user taxes, it is never efficient at coal prices ranging from $25 to $35 to accelerate coal replacement of oil and gas units under the Simple Plan. Even at the lower coal prices, the tight environmental restrictions on burning coal in new baseload units makes accelerated coal replacement uneconomic. However, the user taxes significantly increase the economic attractiveness of accelerated coal replacement. The user taxes on oil make coal replacement of existing oil units economic except at very high coal prices. The user taxes on gas make coal replacement of existing gas units attractive for all the coal cost cases examined. Second, even without the user taxes on utility oil and gas consumption, accelerated nuclear replacement of oil and gas capacity is economical. Therefore, user taxes do not buy any additional oil and gas savings if nuclear replacement is a viable option.

Table 10 combined with tables 8 and 9 can be used to estimate the levels of coal or nuclear replacement that are economic at various coal prices, both with and without the user taxes.

Table 11 indicates the extent to which retirements and replacement of oil and gas units or nuclear units are economic. When only coal replacements are considered viable, no replacements occur under the Simple Plan, irrespective of coal prices. On the other hand, under the Full Plan, retirements and replacements are 16,108 megawatts at coal prices of $25 per ton, 84,808 megawatts at $30 per ton coal prices and scrubbers on converted units, and 52,381 megawatts at $35 coal prices and scrubbers on converted units. The rise in replacements which occurs when coal prices rise from $25 to $30 per ton and scrubbers are required on converted units is entirely the effect of requiring scrubbers. This makes replacements economic relative to conversions. As expected, simply raising the coal price from $30 to $35 lowers the number of replacements.

The picture is quite different when we consider the option of nuclear replacement. First, once the nuclear option is considered there are substantial replacements even with the Simple Plan. These are sensitive to coal prices. At $25 coal prices, there are 51,000 megawatts of replacements but at $35 prices with scrubbers on converted units, replacements increase 155,000 megawatts. Since these are entirely nuclear, the direct relation between coal prices and the extent of replacements is expected; rising coal prices result in the substitution of nuclear replacement for coal conversion.

While the Full Plan encourages coal replacements, its effect on total replacements once the nuclear option is considered is either negative or negligible. At $25 per ton coal prices, the Full Plan actually reduces the extent of replacement. This occurs because the Plan encourages conversion, but these occur at the expense of replacements. In the other two coal cases, the Plan has no effect on the extent of replacement.

The most complete view of the potential impact of the Plan on oil and gas savings is obtained by considering the economic extent of both conversion and replacement. This is described in table 12. If the potential for nuclear replacement is ignored, the extent of replacement and conversion is very sensitive to coal prices, environmental policy and the extent of the NEP. Under the Simple Plan, replacements and conversions are substantial (105,000 megawatts) at $25 coal prices, but considerably more limited once coal prices go to $30 per ton and scrubbers are imposed on converted units. A comparison with Tables 8 and 11 will indicate that in these cases there are no replacements, only conversions.

The Full Plan substantially increases replacements in all of these cases. At $25 coal prices the extent of conversion and replacement is increased from 105,595 megawatts in the Simple Plan to 155,682 in the Full Plan. At $30 coal prices with scrubbers on converted units the Full Plan increases conversions from 19,100 megawatts to 155,682 megawatts. Even at coal prices of $35 per ton the Full Plan increases conversions and replacements from 13,200 megawatts to 72,792 megawatts.

Once the option of nuclear replacement is considered the picture is entirely different. Replacements and conversions, allowing for nuclear replacement, are the same in all cases and equal to total oil and gas capacity. This occurs at each coal price and for the Full and Simple Plans. This last case is of profound significance in that it indicates that:

1. the apparent sensitivity of oil and gas conversions and replacements to coal prices is likely to be a short-term problem unless actions are taken to permanently curtail nuclear growth; and
2. if nuclear development is not curtailed the effect of the NEP is merely to alter the timing of oil and gas conversions and replacements and the relative importance of conversion. Viewed in a time frame long enough to increase nuclear capacity (1987–1990), the NEP will have little impact on total oil and gas saved.

V. CONSISTENCY OF INCENTIVES AND OBJECTIVES IN THE NEP

It is useful to compare conversions and replacements required to meet the objectives of the NEP with those made economically attractive by alternative versions of the Plan. As indicated in Table 3, total replacements and conversions necessary to meet oil and gas saving goals of the Plan are most likely to total 88,173 megawatts, but these requirements could range from a low of 64,085 megawatts to a high of 143,902 megawatts.

As indicated in Table 12, if nuclear replacements provide a viable option, economically attractive replacements and conversions will be more than sufficient to meet these goals. This is true irrespective of coal prices and for the Simple and Full Plans. On the other hand, if the nuclear option is constrained replacements and conversions are sufficient under the Simple Plan only if coal prices are $25 or less and scrubbers are not required on converted units. Under the Full Plan, conversions and replacements are sufficient for coal prices of less than $30 even if scrubbers are required on converted units. Even at $35 coal prices, conversions and replacements are only 17 percent less than the level required under the most likely scenario.

VI. COAL CONVERSION, ACCELERATED REPLACEMENT AND TIGHTNESS IN THE COAL MARKET

The price of coal is the major source of uncertainty in estimating the level of coal conversions and replacements implied by the incentives of the NEP. Therefore, some consideration ought to be given to the capabilities of the coal mining industry to supply the additional demands for coal attributable to the coal conversion program. Tightness in the markets for specific types of coal resources can imply coal prices in the short run which are higher than long-run marginal costs, as can anti-competitive behavior in the coal industry.

It has been suggested that the NEP relies very heavily on the availability of substantial supplies of coal in order to achieve its goals of reduced oil and gas consumption. Consequently, we have considered whether the coal consumption which is implied for the electric utility industry under each of the scenarios considered above, after conversion and when combined with projections of non-utility use of coal, is consistent with estimates of available supplies of coal by 1985. Table 13 contains nine alternative assessments of the available supply of coal by 1985. These nine estimates are based upon three projects: one prepared by the FEA; one by the National Coal Association; and the third by Coal Age magazine. These projections range from 950 million tons to 1.1 billion tons by 1985. All of these estimates are based upon surveys of the current plans of coal producers, and all exhibit a similar anomaly. In each of the projects, the average annual increase in coal production over the period 1975 to 1980 exceeds the average annual increase from 1980 to 1985. Presumably, this reflects the fact that the short-term plans of the coal producing industry are more certain than their long-term plans. We have adjusted each of these estimates by assuming that the absolute annual level of additions to production in each year from 1975 to 1980 will continue from 1981 to 1985 and alternatively by assuming that the average annual growth rate achieved from 1975 to 1980 will also be achieved from 1980 to 1985. The result is, of course, to increase the estimate of potential supply by 1985 to a range of 1.1 to 1.4 billion tons. It should be noted that these are not intended as estimates of what will be achieved by the coal producers, but rather what could be achieved if they simply duplicate their expected performance for the next five years for an additional five years.

In Table 14, we have estimated the coal demand of the electric utility industry by 1985 under each of the growth rate and planned addition scenarios discussed in Section III, and both with and without conversions. With conversions, the industry's consumption of coal ranges from a low of 700 million to a high of 862 million tons of coal. This compares with approximately 800 million tons of coal consumption projected by the NEP.

In order to compare projected coal demands with mining capacity, it is necessary to add to these consumption projections industrial coal usage. The Carter Plan projects industrial coal usage of 480 million tons of coal per year by 1985. After addition, this results in a range of coal consumption of 1.1 to 1.3 billion tons of coal by 1985. While these demands are in excess of what has been projected in each of the surveys conducted by the FEA, the National Coal Association and Coal Age, it is within the range of supply which appears feasible if expected rates of growth in coal production can be maintained after 1980.

In viewing this supply and demand balance, however, it should be kept in mind that the coal demands projected for industrial sources by the Carter Administration seem extremely unrealistic. First, they reflect the assumption of a substantial increase in the growth rate of total energy consumption by industry over its historical pattern. Second, they appear to assume that all growth in boiler fuel use by industry will be made up of coal-fired boilers and finally, that a substantial portion of existing oil- and gas-fired boilers will be converted to coal. Given the small size of industrial boilers, the degree of conversion mandated for industry by the NEP seems unrealistic. In previous sections, we found that the smaller the boiler, the higher the unit cost of conversion. The incentives provided by the Plan do not seem consistent with the NEP projection of the level of industrial conversions. If instead of using industrial coal demand which is projected with the Plan we use industrial demand projected without the Plan, coal demand would be reduced by about 220 million tons by 1985 so the total demand would come well within the bounds of the lower estimates of predicted supply.

This analysis suggests that there need not be substantial excess demand for coal through 1985, even with substantial conversion to coal. Assuming a competitive coal market, coal prices should reflect the marginal production cost of coal. Under these circumstances, delivered coal prices are likely to range from $20 to $30 per ton. If this were the case, economic conversions would tend towards the high end of the range we have estimated. This provides additional evidence that the Full Plan represents substantial overkill.

VII. CONCLUSIONS

The special user taxes on oil and gas consumption impose both costs and benefits on electrical consumers. A proper evaluation of the conversion program in the NEP requires that we compare them. The special electric utility taxes on oil and gas increase electricity costs in three ways.

1. They may increase the operating costs of electrical supply whenever the utility maintains an old oil or gas plant to meet intermediate loads.
2. They may increase the fixed costs of electrical supply whenever the utility makes additional investments in conversion or in accelerated replacement of oil and gas plants and the regulatory commission allows the utility to recover its costs on the undepreciated balance of the retired units.
3. They may increase the financing costs of electrical supply and the outrage costs attributable to insufficient capacity. This will occur whenever the utility makes additional investments in conversion and replacement at the expense of common stockholders, and thus at the expense of investments in capacity to meet load growth. If regulatory commissions deny the utility's investors an adequate return on prematurely retired units, these investors will be less willing to provide capital unless their expected returns are increased.

By examining the consistency of the conversion and replacement requirements in table 3 and the maximum economic amounts of these investments in table 12, we can determine whether these three types of incremental costs are offset by incremental gains (defined in terms of reduced oil and gas consumption). We inferred earlier that about 90,000 megawatts of conversions and replacements are most likely implied by the NEP projections. Three conclusions can be derived from the comparison of this figure with the estimates of economic conversions and replacements shown in table 12:

1. The economical amount of conversions and replacements far exceeds the required levels implied by the NEP projections and is completely insensitive to the special oil and gas taxes. This assumes the Administration is serious about maintaining the feasibility of the nuclear replacement option by reducing licensing delays. If nuclear replacement is generally possible then 100 percent of the oil and gas plants are economically convertible or replaceable without any of the special taxes.
2. If the nuclear replacement option is not generally feasible, then the special taxes on utility consumption of oil and gas probably will not be required to meet the NEP targets. This assumes that coal is priced competitively at marginal cost and that the coal industry's labor and environmental problems are resolved in a manner that is consistent with the energy independence goals of the NEP.
3. The special taxes on utility consumption of oil and gas as provided in the Full NEP are only attractive if we consistently make pessimistic assumptions about the viability of the nuclear replacement option, the cost of coal and the environmental restrictions on the burning of coal in converted units. Furthermore, if conversion costs are unfavorably high because of these assumptions, the increased economic attractiveness of nuclear replacement will provide pressure for its acceleration.

The relative proportions of conversion and replacement are highly sensitive to the form of the Plan, but the total amount of replacements plus conversions is not. If the Administration is primarily interested in meeting the utility fuel consumption targets, the special user taxes do not buy much of an improvement. The special user taxes merely result in transitory deadweight losses to consumers (or investors) which continue until the industry completely adjusts its generating capacity.

We conclude that under a reasonably wide set of assumptions, the Full Plan probably does not provide incremental social benefits (in terms of reduced oil and gas consumption) which warrant the social and private costs likely to be incurred from these special taxes on utility use of oil and gas. Similarly, our analysis suggests that mandatory restrictions on the use of natural gas in electric utility boilers are unnecessary if the Administration's targets are considered seriously. Under a very wide range of assumptions, simply raising the Btu-equivalent price of oil and gas to the world crude oil price provides a very strong economic incentive for coal conversion and accelerated replacement of oil and gas facilities. Rather than mandating conversion and early retirement of natural gas facilities, the NEP coal conversion program would be improved if it spent the administrative costs required to implement its directives (and likely exceptions) on the removal of artificial constraints on the acceleration of the industry's nuclear and coal construction plans. Ordering coal conversions will definitely lead to higher costs of regulation without necessarily leading either to improved resource allocation or to a greater degree of energy and political independence.

We are quite sensitive to the uncertainties in the basic data used to draw the above conclusions. Given that our answers are dependent on some assumptions of unknown reliability—an uncertainty that is unlikely to be resolved quickly—then the special taxes on utility consumption of oil and gas may be a method for insuring that the NEP targets are met under the worst possible circumstances. Protection against "the worst case" may be a reasonable justification for some types of federal intervention in energy markets, but not at infinite insurance premiums. Our analysis suggests that these conversion and replacement incentives are an extremely expensive form of coverage. This again points up the Plan's unnecessary complications.

As an alternative, we would suggest that a simplified form of the NEP conversion incentives be implemented, a form which would exclude both the special user taxes on utility consumption of oil and gas and the additional tax credits or rebates on conversion investments. If the industry does not seem to be able to meet the implied conversion and early retirement targets (allowing for some slippage in the 1985 target deadline), the federal government might then discuss ways to directly subsidize the investments designed to decrease the industry's use of oil and gas. Such methods might include the tax exemption of interest on the debt used to finance conversion investments, federal loan guarantees on conversion investments, or the use of customer-contributed forms of capital in order to expedite the replacement of uneconomic units.

We find that the coal conversion program discussed in the NEP exhibits some of the typical flaws in recent federal energy policy. The coal conversion planks in the Plan seem to have been hurriedly and sloppily thrown together. They could easily increase the regulatory costs associated with energy transactions without providing the commensurate benefits that result from pricing resources at their correct economic values. It is not without precedent that we worry that the economic tinkering associated with this Plan may simply provide the stimulus for increased Federal intervention (or "counter-tinkering") later on. Although the objectives of the coal conversion and accelerated replacement program are economically justified and the targets presented in the NEP are not unreasonable, the measures contained in this program are focused on the wrong problem. The electric utilities are no less likely than other firms to make economically correct decisions when given the right prices and regulatory incentives for improved efficiency in production. For example, accelerated replacements of oil and gas units are already included to a considerable extent in the industry's current construction program, and as the financial posture of the industry continues to improve, this trend should become stronger. We believe, therefore, that federal policy in this arena should be directed at improving the informational content of energy prices in the simplest possible manner and at removing uneconomic institutional constraints on the rate at which the electric utilities can reconfigure their generating plant.

TABLE 1.—PROJECTED OIL AND GAS USAGE IN 1985

[In million barrels of oil equivalent per day]

Scenario	Oil: 4.7 percent growth (1)	Oil: 5.25 percent growth (2)	Gas: 4.7 percent growth (3)	Gas: 5.25 percent growth (4)
(1) FEA planned additions; capacity factor for new coal and nuclear equals 60, 60	1.57	2.03	0.63	0.92
(2) Same as case 1, with capacity factor for new coal and nuclear lowered to 50	2.32	2.77	1.10	1.39
(3) Same as case 1, with capacity factor for new coal raised to 65	1.15	1.61	.36	.65
(4) Same as case 1, with coal additions increased by 10 percent	1.39	1.85	.51	.80
(5) Same as case 1, with nuclear additions decreased by 10 percent	1.77	2.30	.75	1.09
(6) Same as case 1, with nuclear additions decreased by 20 percent	1.96	2.56	.88	1.26
Targets given in the Carter plan	1.33		.50	

Source: NERA estimates.

TABLE 2.—CONVERSION FROM OIL AND GAS TO COAL REQUIRED TO MEET NEP UTILITY FUEL CONSUMPTION TARGETS IN 1985

[In megawatts]

Scenario	Percent growth: Oil 4.7 (1)	Oil 5.25 (2)	Gas 4.7 (3)	Gas 5.25 (4)
(1) FEA planned additions; capacity factor for new coal and nuclear equals 60, 60	16,315	31,916	1,596	16,944
(2) Same as case 1, with capacity factor for new coal and nuclear lowered to 50	46,205	64,983	26,143	40,897
(3) Same as case 1, with capacity factor for new coal raised to 65		16,941		1,656
(4) Same as case 1, with coal additions increased by 10 percent	4,223	25,723	413	11,105
(5) Same as case 1, with nuclear additions decreased by 10 percent	22,942	42,456	8,483	25,477
(6) Same as case 1, with nuclear additions decreased by 20 percent	29,616	50,014	14,776	34,009

Source: NERA estimates.

TABLE 3.—REQUIRED COAL CONVERSIONS ADDED TO THE BASELOAD REPLACEMENTS CURRENTLY IMBEDDED IN THE UTILITY INDUSTRY'S CONSTRUCTION PROGRAM

[In megawatts electrical]

Scenario	Oil (1)	Gas (2)	Total (3)
(1) FEA planned additions; capacity factor for new coal and nuclear equals 60, 60	59,728	28,445	88,173
(2) Same as case 1, with capacity factor for new coal and nuclear lowered to 50	91,206	52,696	143,902
(3) Same as case 1, with capacity factor for new coal raised to 65	44,082	20,003	64,085
(4) Same as case 1, with coal additions increased by 10 percent	50,585	24,934	75,519
(5) Same as case 1, with nuclear additions decreased by 10 percent	68,311	36,155	104,466
(6) Same as case 1, with nuclear additions decreased by 20 percent	75,427	43,568	118,998

Source: NERA estimates of the amount of oil and gas replacements planned by the utilities given the FEA estimates of planned additions. These estimates of replacement investments vary from 38,000 to 71,000 megawatts depending on the growth rate of electricity demand. An 18-percent reserve margin and a 60-percent system load factor are assumed.

TABLE 4.—ESTIMATED MAXIMUM EXPENDITURE[1] ON COAL CONVERSION THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS (ALLOWING FOR COAL REPLACEMENT OF EXISTING UNITS)

[In 1977 dollars per kilowatt]

Life remaining after completing conversion (years)	Simple plan[2]			Full plan[2]		
	Coal at $25 per ton, no scrubber necessary on conversions[3]	Coal at $30 per ton, scrubber necessary on conversions[3]	Coal at $35 per ton, scrubber necessary on conversions[3]	Coal at $25 per ton, no scrubber necessary on conversions[3]	Coal at $30 per ton, scrubber necessary on conversions[3]	Coal at $35 per ton, scrubber necessary on conversions[1]
	(1)	(2)	(3)	(4)	(5)	(6)
Oil plant:						
5	[4] $169.73	[4] $82.65	[4] $45.75	[5] $234.11	[5] $136.15	[4] $94.65
10	[4] 275.11	[4] 133.96	[4] 74.16	[5] 379.48	[5] 220.69	[4] 153.41
15	[4] 340.55	[4] 165.83	[4] 91.79	[5] 469.74	[5] 273.18	[4] 189.89
20	[4] 476.47	[4] 232.02	[4] 128.45	[5] 657.23	[5] 382.22	[4] 265.70
25	[4] 503.01	[4] 247.38	[4] 136.94	[5] 700.72	[5] 407.51	[4] 283.27
30	[4] 527.59	[4] 256.91	[4] 142.22	[5] 727.73	[5] 423.22	[4] 294.19
Gas plant:						
5	[4] 169.73	[4] 82.65	[4] 45.75	[5] 292.72	[5] 198.08	[5] 186.87
10	[4] 275.11	[4] 133.96	[4] 74.16	[5] 474.48	[5] 321.07	[5] 302.91
15	[4] 340.55	[4] 165.83	[4] 91.79	[5] 587.30	[5] 397.41	[5] 374.93
20	[4] 476.47	[4] 232.02	[4] 128.45	[5] 657.40	[5] 444.85	[5] 419.69
25	[4] 508.01	[4] 247.38	[4] 136.94	[5] 700.88	[5] 474.26	[5] 447.44
30	[4] 527.59	[4] 256.91	[4] 142.22	[5] 727.90	[5] 492.55	[5] 464.69

[1] Maximum economic expenditure on coal conversion is defined as the present worth of fuel savings adjusted for investment tax credits of 10 percent in cols. (1), (2), and (3) and 20 percent in cols. (4), (5), and (6).

[2] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per thousand cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3 to $3.30 per thousand cubic feet.

[3] See text and app. A for derivation of calculations and estimates in tables A-1 and A-2.

[4] If actual conversion capital costs are greater than this estimate of the maximum economic expenditure on conversion, the oil or gas capacity would be maintained as intermediate load-serving capacity.

[5] If actual conversion capital costs are greater than this estimate of the maximum economic expenditure on conversion, the oil or gas capacity would be replaced with the new coal baseload-serving capacity.

Source: NERA estimates.

TABLE 5.—ESTIMATED MAXIMUM EXPENDITURE[1] ON COAL CONVERSION THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS (ALLOWING FOR NUCLEAR REPLACEMENT OF EXISTING UNITS)

[In 1977 dollars per kilowatt]

Life remaining after completing conversion (years)	Simple plan[2]			Full plan[2]		
	Coal at $25 per ton, no scrubber necessary on conversions[3]	Coal at $30 per ton, scrubber necessary on conversions[3]	Coal at $35 per ton, scrubber necessary on conversions[3]	Coal at $25 per ton, no scrubber necessary on conversions[3]	Coal at $30 per ton, scrubber necessary on conversions[3]	Coal at $35 per ton, scrubber necessary on conversions[3]
	(1)	(2)	(3)	(4)	(5)	(6)
Oil plant:						
5	[4] $169.73	[4] $82.65	[4] $28.87	[5] $234.11	[5] $94.75	[5] $32.48
10	[4] 275.11	[4] 133.96	[4] 46.79	[5] 379.48	[5] 153.58	[5] 52.64
15	[4] 340.55	[4] 165.83	[4] 57.92	[5] 469.74	[5] 190.09	[5] 65.16
20	[4] 476.47	[4] 189.14	[4] 64.83	[5] 542.81	[5] 212.78	[5] 72.94
25	[4] 508.01	[4] 201.65	[4] 69.12	[5] 57.870	[5] 226.85	[5] 77.76
30	[4] 527.59	[4] 209.42	[4] 71.79	[5] 601.02	[5] 235.60	[5] 80.76
Gas plant:						
5	[4] 169.73	[4] 82.65	[4] 28.87	[5] 241.70	[5] 94.75	[5] 32.48
10	[4] 275.11	[4] 133.96	[4] 46.79	[5] 391.77	[5] 153.58	[5] 52.64
15	[4] 340.55	[4] 165.83	[4] 57.92	[5] 484.92	[5] 190.09	[5] 65.16
20	[4] 476.47	[4] 189.14	[4] 64.83	[5] 542.81	[5] 212.78	[5] 72.94
25	[4] 508.01	[4] 201.65	[4] 69.12	[5] 578.70	[5] 226.85	[5] 77.76
30	[4] 527.59	[4] 209.42	[4] 71.79	[5] 601.02	[5] 235.60	[5] 80.76

[1] Maximum economic expenditure on coal conversion is defined as the present worth of fuel savings adjusted for investment tax credits of 10 percent in cols. (1), (2), and (3) and 20 percent in cols. (4), (5), and (6).

[2] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per thousand cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3 to $3.30 per thousand cubic feet.

[3] See text and app. A for derivation of calculations and estimates in tables A-1 and A-3.

[4] If actual conversion capital costs were greater than the estimate of the maximum economic expenditure on conversion, the oil or gas capacity would be maintained as intermediate load-serving capacity. However, accelerated nuclear replacement is economic under both forms of the plan; therefore, this never occurs.

[5] If actual conversion capital costs are greater than this estimate of the maximum economic expenditure on conversion, the oil or gas capacity would be replaced with new nuclear baseload-serving capacity.

Source: NERA estimates.

TABLE 6.—ESTIMATED COSTS OF COAL CONVERSION BY COST CATEGORY

[In 1977 dollars per kilowatt]

	Amount (megawatts electrical)	Base cost	Base cost with scrubber	Outage and substitution costs during conversion		Total estimated cost of conversion		
				Minimum [1]	Maximum [2]	Minimum	Maximum	Weighted average estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Oil plant:								
Conversion	[3] 18,463	[4] $10.50	[5] $85.50	$2.19	$37.78	$12.69	$123.28	[6] $74.30
Reconstruction	[4] 82,427	[7] 250.00	[4] 325.00	2.19	37.78	252.19	362.78	[6] 313.64
Gas plant:								
Conversion	[3] 2,411	[4] 20.00	[5] 95.00	2.19	37.78	22.19	132.78	[8] 95.78
Reconstruction—Approximate unit sizes:								
Greater than 700 MWe	[3] 3,629	[7] 407.37	[7] 476.37	2.19	37.78	407.56	514.15	[8] 479.65
500 to 700	[3] 8,468	[7] 437.42	[7] 510.88	2.19	37.78	439.61	548.66	[8] 511.93
200 to 500	[3] 20,142	[7] 475.26	[7] 584.34	2.19	37.78	477.45	622.12	[8] 567.58
Less than 200	[3] 20,142	[7] 566.50	[7] 712.34	2.19	37.78	568.69	750.12	[8] 677.20

[1] Reflects zero dollars per kilowatt reliability cost and $2.19 per kilowatt substitution cost. See text for explanation.

[2] Reflects $18.73 per kilowatt reliability cost and $19.05 per kilowatt substitution cost. See text for explanation.

[3] Source: NERA estimates based on T. Burbank, "The Phasing Out of Oil and Gas Used for Boiler Fuel: Constraints and Incentives," Edison Electric Institute, Mar. 7, 1977, p. 12 and Federal Power Commission, "Steam-Electric Plant Construction Cost and Annual Production Expenses," 1974.

[4] Source: "Evaluation of the Feasibility of Total Conversion to Coal Firing, 20-Plant Report," prepared by PEDCO-Environmental Specialists, Inc., for the U.S. Environmental Protection Agency, Dec. 31, 1976.

[5] Based on scrubber cost of $75 per kilowatt.

[6] 64 percent of all steam oil capacity is in the Northeast Power Coordinating Council, the Southeast Electric Reliability Council and the Western Systems Coordinating Council. A weight of 0.64 is used for the sum of the base cost with scrubber, the low reliability cost and the low substitution cost. A weight of 0.36 is used for the sum of the base conversion cost without scrubber, the high reliability cost and the high substitution cost. See text for explanation of reliability and substitution cost assumptions.

[7] Source: FPC, National Power Survey, "Supplement to Preliminary Report of the Technical Advisory Committee on Fuels" on the "Fuel Oil Conservation Target for the Electric Utility Industry Outlined in the President's Oct. 8, 1974, Economic Message and the Accompanying Fact Sheet," Oct. 30, 1974. The utilities of the State of Texas, "Texas Railroad Commission Docket No. 660—Reducing or Eliminating Natural Gas as a Boiler Fuel in Texas," EBASCO Services Inc., May 1975.

[8] 94 percent of all steam gas capacity is located in the Southwest Power Pool and the Electric Reliability Council of Texas. The conversion of such units would significantly weaken service reliability during the conversion period. 50 percent of the units are assumed to require scrubbers and the maximum reliability substitution fuel cost production are assumed. See text for explanation of reliability and substitution cost assumptions.

Source: NERA estimates.

TABLE 7.—PROJECTED AGE DISTRIBUTION OF OIL AND GAS CAPACITY IN 1985

Age	Remaining life	Percent of gas capacity in vintage [1]	Percent of oil capacity in vintage [2]
	(1)	(2)	(3)
Less than 10	30-40	12.2	23.6
10 to 15	25-30	30.4	17.4
15 to 20	20-25	21.6	15.8
20 to 25	15-20	11.8	15.1
25 to 30	10-15	12.8	12.2
30 to 35	5-10	8.4	10.9
35 to 40	0-5	2.8	5.0

[1] Based on NERA estimate of 1985 oil capacity at 100,890 MW.

[2] Based on NERA estimate of 1985 gas capacity at 54,800 MW.

Source: Preliminary EEI draft entitled "Constraints and Incentives for Phasing Out Natural Gas as Boiler Fuel," circulated by King Mallory of Middle South Services, Inc.

TABLE 8.—MAXIMUM CONVERSIONS OF OIL AND GAS CAPACITY THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS (ALLOWING FOR COAL REPLACEMENT OF EXISTING UNITS)

[In megawatts electrical]

Type of plant	Simple plan [1]			Full plan [1]		
	Coal at $25 per ton, no scrubbers on converted units (1)	Coal at $30 per ton, scrubbers on converted units (2)	Coal at $35 per ton, scrubbers on converted units (3)	Coal at $25 per ton, no scrubbers on converted units (4)	Coal at $30 per ton, scrubbers on converted units (5)	Coal at $35 per ton, scrubbers on converted units (6)
Convertible oil [2]	[3] 18,463	[4] 17,000	12,000	[3] 18,463	[3] 18,463	18,000
Reconstructible oil [2]	69,000	0	0	76,000	50,000	0
Subtotal, oil	87,463	17,000	12,000	94,463	68,463	18,000
Convertible gas [2]	[3] 2,411	2,100	1,200	[3] 2,411	[3] 2,411	[3] 2,411
Reconstructible gas unit size:						
700 MW [2]	2,500	0	0	3,400	0	0
500 to 700 MW [2]	5,100	0	0	7,100	0	0
200 to 500 MW [2]	7,500	0	0	17,700	0	0
200 MW [2]	0	0	0	14,500	0	0
Subtotal, gas	17,511	2,100	1;200	45,111	2,411	2,411
Total	104,974	19,100	13,200	139,574	70,874	20,411

[1] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per thousand cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3 to $3.30 per thousand cubic feet.

[2] The following conversion costs are assumed:

[In dollars per kilowatt]

	With scrubber	Without scrubber
Convertible oil	101.76	30.00
Reconstructible oil	326.00	275.58
Convertible gas	134.28	57.78
Reconstructible gas unit size:		
700 MW	514.00	445.00
500 to 700 MW	549.00	475.00
200 to 500 MW	622.00	513.00
200 MW	750.00	604.00

[3] Estimate equals maximum number of plants in this cost category. (See table 6.)

[4] Where the estimate is not equal to the maximum number of plants in the cost category, the oil conversion estimate is rounded to thousands of megawatts electrical and the gas conversion estimate is rounded to hundreds of megawatts electrical.

Source: Tables 4, 6, and 7.

TABLE 9.—MAXIMUM CONVERSIONS OF OIL AND GAS CAPACITY THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS (ALLOWING FOR NUCLEAR REPLACEMENT OF EXISTING UNITS)

[In megawatts electrical]

Type of plant	Simple plan [1]			Full plan [1]		
	Coal at $25 per ton, no scrubbers on converted units	Coal at $30 per ton, scrubbers on converted units	Coal at $35 per ton, scrubbers on converted units	Coal at $25 per ton, no scrubbers on converted units	Coal at $30 per ton, scrubbers on converted units	Coal at $35 per ton scrubbers on converted units
	(1)	(2)	(3)	(4)	(5)	(6)
Convertible oil [2]	[3] 18,463	[4] 17,000	0	[3] 18,463	[3] 17,300	0
Reconstructible oil [2]	69,000	0	0	76,000	0	0
Subtotal, oil	87,463	17,000	0	94,463	17,300	0
Convertible gas [2]	2,411	2,100	0	2,411	[3] 2,200	0
Reconstructible gas unit size:						
700 MW [2]	2,500	0	0	3,000	0	0
500 to 700 MW [2]	5,100	0	0	6,500	0	0
200 to 500 MW [2]	7,500	0	0	14,000	0	0
200 MW [2]	0	0	0	0	0	0
Subtotal, gas	17,511	2,100	0	25,911	2,200	0
Total	104,974	19,100	0	120,374	19,500	0

[1] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per thousand cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3 to $3.30 per thousand cubic feet.

[2] The following conversion costs are assumed:

[In dollars per kilowatt]

	With scrubber	Without scrubber
Convertible oil	101.76	30.00
Reconstructible oil	326.00	275.58
Convertible gas	134.28	57.78
Reconstructible gas unit size:		
700 MW	514.00	445.00
500 to 700 MW	549.00	475.00
200 to 500 MW	622.00	513.00
200 MW	750.00	604.00

[3] Estimate equals maximum number of plants in this cost category. (See table 6.)

[4] Where the estimate is not equal to the maximum number of plants in the cost category, the oil conversion estimate is rounded to thousands of megawatts electrical and the gas conversion estimate is rounded to hundreds of megawatts electrical.

Source: Tables 5, 6, and 7.

TABLE 10.—NET PRESENT WORTH OF ECONOMIC GAINS [1] FROM REPLACEMENT OF OLD OIL AND GAS PLANTS UNDER VARYING ASSUMPTIONS

[In 1977 dollars per kilowatt]

Life remaining in plant (years)	Simple plan [2]				Full plan [2]			
	Coal replacement at $25 per ton [3]	Coal replacement at $30 per ton	Coal replacement at $35 per ton	Nuclear replacement [4]	Coal replacement at $25 per ton [3]	Coal replacement at $30 per ton	Coal replacement at $35 per ton	Nuclear replacement [4]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Oil plant [5]								
5	[6] −5.0	−46.9	−87.7	35.9	46.8	4.9	−35.9	87.6
10	−8.2	−76.0	−142.2	58.0	75.8	8.0	−58.2	142.0
15	−10.1	−94.1	−176.0	71.8	93.8	9.9	−72.1	175.7
20	−11.3	−105.3	−197.0	80.4	105.0	11.1	−80.7	196.7
25	−12.1	−112.3	−210.1	85.7	112.0	11.8	−86.0	209.7
30	−12.5	−116.6	−218.2	89.0	116.3	12.2	−89.3	217.8
Gas plant:								
5	−5.0	−46.9	−87.7	35.9	162.3	120.5	77.6	203.2
10	−8.2	−76.0	−142.2	58.0	263.1	195.3	129.1	329.3
15	−10.1	−94.1	−176.0	71.8	457.6	373.7	291.7	539.5
20	−11.3	−105.3	−197.0	80.4	512.3	418.3	326.5	603.9
25	−12.1	−112.3	−210.1	85.7	546.1	445.9	348.1	643.9
30	−12.5	−116.6	−218.2	89.0	567.2	463.1	361.6	668.7

[1] For derivation and explanation of computation see app. A and text.
[2] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per thousand cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3 to $3.30 per thousand cubic feet.
[3] Coal capacity cost including scrubber is $600 per kilowatt (in 1977 dollars); 10-percent tax credit on replacement investment.
[4] Nuclear capacity cost is $800 per kilowatt (in 1977 dollars); 10-percent investment tax credit on replacement investments.
[5] The following running costs are assumed:

[In mills per kilowatt-hour]

	Nuclear	Coal	Oil	Natural gas: Remaining life <10 yr.	Natural gas: Remaining life >10 yr.
Column:					
1		13.60	24.0	24.0	24.0
2		15.70	24.0	24.0	24.0
3		17.75	24.0	24.0	24.0
4	8		24.0	24.0	24.0
5		13.60	26.6	32.4	35.7
6		15.70	26.6	32.4	35.7
7		17.75	26.6	32.4	35.7
8	8		26.6	32.4	35.7

[6] Negative signs imply welfare losses from early retirement, positive signs imply welfare gains.

Source: NERA estimates; for detailed explanation see text.

TABLE 11.—ESTIMATED MAXIMUM REPLACEMENT[1] OF OIL AND GAS CAPACITY THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS

	Megawatts electrical					
	Simple plan[2]			Full plan[2]		
	Coal at $25 per ton[3]	Coal at $30 per ton[4]	Coal at $35 per ton[4]	Coal at $25 per ton[3]	Coal at $30 per ton[4]	Coal at $35 per ton[4]
	(1)	(2)	(3)	(4)	(5)	(6)
Allowing for coal replacement:						
Oil plants	0	0	0	6, 427	32, 427	0
Gas plants	0	0	0	9, 681	52, 381	52, 381
Total	0	0	0	16, 108	84, 808	52, 381
Allowing for nuclear replacement:						
Oil plants	13, 427	64, 100	[5] 100, 890	6, 427	83, 590	[5] 100, 890
Gas plants	37, 581	52, 692	[5] 54, 792	28, 881	52, 592	[5] 54, 792
Total	51, 008	136, 792	[5] 155, 682	35, 308	136, 182	[5] 155, 682

[1] See app. A and table 10 for derivation of the early retirement and replacement benefit calculation.
[2] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per million cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3–$3.50 per million cubic feet.
[3] No scrubbers on converted units.
[4] Scrubbers on converted units.
[5] Estimate reflects total capacity of this type projected for 1985. (See table 6.)

Source: NERA estimates; see tables 6, 7, 8, 9, and 10.

TABLE 12.—ESTIMATED MAXIMUM CONVERSIONS AND REPLACEMENTS OF OIL AND GAS CAPACITY THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS

	Megawatts electrical					
	Simple plan[1]			Full plan[1]		
	Coal at $25 per ton[2]	Coal at $30 per ton[3]	Coal at $35 per ton[3]	Coal at $25 per ton[2]	Coal at $30 per ton[3]	Coal at $35 per ton[3]
	(1)	(2)	(3)	(4)	(5)	(6)
Allowing for coal replacement:						
Oil plants	87, 784	17, 000	12, 000	100, 890	100, 890	18, 000
Gas plants	17, 811	2, 100	1, 200	54, 792	54, 792	54, 792
Total	105, 595	19, 100	13, 200	155, 682	155, 682	72, 792
Allowing for nuclear replacement:						
Oil plants	100, 890	100, 890	100, 890	100, 890	100, 890	100, 890
Gas plants	54, 792	54, 792	54, 792	54, 792	54, 792	54, 792
Total	155, 682	155, 682	155, 682	155, 682	155, 682	155, 682

[1] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per million cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3–$3.50 per million cubic feet.
[2] No scrubbers on converted units.
[3] Scrubbers on converted units.

Source: NERA estimates; see Tables 8, 9, and 11.

TABLE 13.—ESTIMATES OF TOTAL COAL CAPACITY IN 1985 BY SOURCE

	Millions of tons				
	Base production (1)	Retirements [1] (2)	Additions (planned plus possible) (3)	Total capacity 1985 (4)	Percent growth (5)
As estimated by:					
Federal energy administration	603.42	199.13	546.35	950.64	4.22
National Coal Association	648.00	194.40	499.87	953.47	3.94
Coal Age Survey	648.00	194.40	671.08	1,124.68	5.67
Assuming maintenance of average absolute growth in 1976–81 to 1985:					
Federal Energy Administration	603.42	199.13	705.49	1,109.78	5.70
National Coal Association	648.00	194.40	638.57	1,092.17	5.36
Coal Age Survey	648.00	194.40	859.15	1,312.75	7.32
Assuming maintenance of average annual rate 1976–81 to 1985:					
Federal Energy Administration	603.42	199.13	777.76	1,182.05	6.30
National Coal Association	648.00	194.40	696.25	1,150.65	5.91
Coal Age Survey	648.00	194.40	937.39	1,440.99	8.32

[1] Calculated at 3 percent of base.

Source: Federal Energy Administration, Coal Mine Expansion Study, FEA/G-76/376, May 1976. National Coal Association, A Study of New Mine Additions and Major Expansion Plans of the Coal Industry, August 1976. George F. Nielsen, "Coal Mine Development and Expansion Survey," Coal Age, February 1977.

TABLE 14.—COAL DEMAND UNDER ALTERNATIVE SCENARIOS

[In millions of tons]

Scenario	No conversions (1)	With conversions: 4.7-percent growth (2)	With conversions: 5.25-percent growth (3)
FEA planned additions; CF [1] for new coal and nuclear=60, 60	674	713	781
Same as case 1, with CF [1] for new coal and nuclear lowered to 50	635	788	862
Same as case 1, with CF [1] for new coal raised to 65	738	738	782
Same as case 1, with coal additions increased by 10 percent	698	708	778
Same as case 1, with nuclear additions decreased by 10 percent	674	743	822
Same as case 1, with nuclear additions decreased by 20 percent	674	771	858
Electrical coal usage predicted by the Carter plan	[2] 789	[3] 799	
Industrial coal usage predicted by the Carter plan	[2] 260	[3] 481	

[1] CF stands for capacity factor.
[2] Without the plan.
[3] With the plan.

Source: NERA estimates.

Appendix A

Derivation of Estimates of Maximum Economic Expenditures of Coal Conversion

In section IV, we discussed our estimates of the maximum private expenditure a utility could economically make on the conversion of a kilowatt of oil or gas capacity to coal. The estimates given in table 4 were calculated as the minimum of two maximum bounds on the efficient conversion investment. The first bound is derived by comparing the conversion and "do-nothing" options on a plant-by-plant basis as if an early retirement (and replacement) alternative did not exist. The second bound is derived by comparing the coal replacement and the conversion options directly as if the "do-nothing" alternative were infeasible. The estimates given in table 5 are computed in exactly the same manner as those in table 4 except a nuclear (instead of coal) replacement option is considered. In this section we discuss our estimates of the three sets of individual maximum investments in coal conversion capital.

A. MAXIMUM ECONOMIC CONVERSION INVESTMENTS WITH REPLACEMENT OPTION RULED OUT

Table A-1 shows the maximum private economic expenditures on coal conversion on a per-kilowatt basis calculated from comparing the coal conversion with the "do-nothing" alternatives as if the early retirement and replacement options did not exist. The maximum private investments are exactly equal to the present value per kilowat of the conversion fuel cost savings adjusted for the conversion investment tax credit.

The formula used to calculate these bounds is the following:

$$\dot{X}_1=\frac{(8{,}760)(CF)(D)}{(1-ITC)}\left[\frac{1-(1+i)^{-(N+1)}}{1-(1+i)^{-1}}-1\right] \quad [1]$$

where:

X^1 = the maximum economic expenditure on coal conversion derived by comparing the conversion and "do-nothing" alternatives.
CF = capacity factor of the converted unit.
D = fuel cost savings per kilowatt-hour from converting rather than doing nothing.
8,760 = hours per year.
ITC = the investment tax credit rate for conversion.
i = the discount rate.
N = the number of years remaining in the life of the plant.

There are four systematic but fairly qualitative conclusions to be drawn from table A-1:

1. The economics of both oil and gas conversion look better for newer oil and gas plants. The newer the plants, the greater the fuel savings from conversion;
2. If coal prices are raised by 20 percent and scrubbers are mandated universally, the benefits of conversion are cut from 50 to 75 percent of their previous values;
3. With the Simple NEP, the economics of oil and gas conversion are equivalent; however, with the Full NEP, gas conversion looks much beter than oil conversion assuming that early retirement and replacement is not a viable option; and
4. Both the Simple and Full NEP make the conversion of at least some portion of the 1985 stock of oil and gas capacity economically attractive. On a per-kilowatt basis, the present worth of the fuel savings from conversion (assuming that retirement and replacement with a new unit is not possible) can justify economic expenditures on coal conversion almost as large as the cost of a new nuclear plant.

With the Simple NEP, the running costs of oil and gas plants are roughly the same since the fuel costs are equivalent on a per-million Btu basis. With coal prices at about $25/ton and assuming scrubbers are never necessary on converted units, the present worth of the fuel savings from conversion, adjusted for the investment tax credit, might make it efficient for a utility to invest $170 to $528 per kilowatt on coal conversion of both oil and gas plants. With a universal requirement of scrubbers on converted units, and coal at $30/ton, the range is cut to $83 to $257 per kilowatt. Raising the price of coal by still another $5/ton or 17 percent reduces these investments by 45 percent. The Full NEP taxes utilities' consumption of natural gas at a much higher rate than their consumption of oil. Therefore, the range of maximum private investments in gas to coal conversions under the Full NEP is 74 percent higher than that for oil to coal conversions. With coal at $25/ton and no scrubbers, the range of maximum private investment in oil conversion is from $234 to $728 per kilowatt. For natural gas conversions, the bound varies from $330 to almost $1200 per kilowatt. These expenditures are cut by 58 percent if coal costs increase to $30/ton and scrubbers are universally mandated on converted units; and by 80 percent if coal prices increase to $35/ton.

B. MAXIMUM ECONOMIC CONVERSION INVESTMENTS WITH NUCLEAR REPLACEMENT AND "DO-NOTHING" OPTIONS RULED OUT

In table A-2, we show maximum investments in conversion of oil and gas plants derived by comparing the coal replacement decision directly with the conversion option as if the "do-nothing" alternative is not possible. All replacement coal units are assumed to require scrubbers and their associated running cost penalties.

The formula used to calculate the bounds in Table A-2 is the following:

$$\dot{X}_2 = \frac{C\left(\frac{1}{1-(1+i)}-35\right)(1-ITC')(1-(1+i)^{-N})}{(1-ITC)} - \frac{(8,760)(CF')(D')}{(1-ITC)}\left[\frac{1-(1+i)^{-(N+1)}}{1-(1+i)^{-1}}-1\right] \quad [2]$$

where:

X^2 = the maximum economic expenditure on coal conversion derived by comparing the conversion and replacement alternatives.
i = the discount rate.
35 = lifetime in years of a new plant.
ITC' = investment tax credit rate for new plants.
C = capital cost per kilowatt for replacement plant.
ITC = investment tax credit rate for converted plants.
N = remaining lifetime of converted unit.
CF' = capacity factor of replacement unit.
D' = fuel cost savings per kilowatt-hour from replacing rather than converting.

Four qualitative observations can be made from examining table A-2 (and comparing it with table A-1):

1. As in the previous calculation, the benefits from conversion are higher (vis-a-vis early retirement and coal replacement) when the plant is newer;
2. Higher coal costs and the universal requirement of scrubbers on converted units always lessen the attractiveness of conversion relative to retirement;
3. Under the Simple Plan, the coal replacement option never restricts the maximum private investment in oil or gas conversion as tightly as does the "do-nothing" alternative. This result is independent of the age of the plant.
4. With the Full NEP, the replacement option restricts the conversion expenditures more tightly than does the "do-nothing" option for gas plants, but not for oil plants.

C. MAXIMUM ECONOMIC CONVERSION INVESTMENTS WITH THE "DO-NOTHING" OPTION RULED OUT

Table A-3 replicates the estimates of maximum economic expenditures on coal conversion allowing for a nuclear instead of a coal replacement option. Table A-3 was prepared by substituting nuclear capacity and running cost estimates for the parallel figures for coal plants in Equation (2). The nuclear capital and running cost figures assumed make the nuclear replacement option much more attractive than the coal alternative at capacity factors of 60 percent or greater. The economic attractiveness of the nuclear baseload alternative constrains the economic expenditure on coal conversion to levels which are 83 percent of the coal replacement case when coal costs \$25/ton, 48 percent when coal costs \$30/ton and 16 percent when coal costs \$35/ton. For a kilowatt of oil or gas capacity with 15 years of useful life remaining, about \$58 to \$431 can be economically spent on coal conversion (depending on the price of coal) under the Simple Plan before replacement with a nuclear plant is more economic. If the Full Plan is implemented, the user taxes would increase the range of maximum expenditures on conversion for a 15-year-old unit by only 12 to 13 percent.

TABLE A-1.—ESTIMATED MAXIMUM EXPENDITURE[1] ON COAL CONVERSION THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS (REPLACEMENT OPTION RULED OUT)[2]

[1977 dollars per kilowatt]

Life remaining after completing conversion (years)	Simple plan[3]			Fup nalll[3]		
	Coal at $25 ton per[4]	Coal at $30 per ton[5]	Coal at $35 per ton[5]	Coal at $25 per ton[4]	Coal at $30 per ton[5]	Coal at $35 per ton[5]
	(1)	(2)	(3)	(4)	(5)	(6)
Oil plant:						
5	$169.73	$82.65	$45.75	$234.11	$136.15	$94.65
10	275.11	133 96	74.16	379.48	220.69	153.41
15	340.55	165.83	91.79	469.74	273.18	189.89
20	476.47	232.02	128.45	657.23	382.22	265.70
25	508.01	247.38	136.94	700.72	407.51	283.27
30	527.59	256.91	142.22	727.73	423.22	294.19
Gas plant:						
5	169.73	82.65	45.75	330.41	232.45	190.95
10	275.11	133.96	74.16	535.58	376.79	309.52
15	340.55	165.83	91.79	772.90	576.34	493.02
20	476.47	232.02	128.45	1,081.40	806.39	689.89
25	508.01	247.38	136.94	1,152.96	859.75	735.51
30	527.59	256.91	142.22	1,197.40	892.89	763.87

[1] Maximum economic expenditure on coal conversion is defined as the present worth of fuel savings adjusted for investment tax credits of 10 percent in cols. (1), (2), and (3) and 20 percent in cols. (4), (5), and (6).
[2] See text and app. A for derivation of calculation.
[3] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per million cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3–$3.30 per million cubic feet.
[4] No scrubber necessary on conversions.
[5] Scrubber necessary on conversions.

Note.—The following running costs are assuned:

[In mills per kilowat-hour]

	Coal	Oil	Natural gas: Remaining life less than 10 yr	Natural gas: Remaining life more than 10 yr
Col. 1	12.5	24.0	24.0	24.0
Col. 2	18.4	24.0	24.0	24.0
Col. 3	20.9	24.0	24.0	24.0
Col. 4	12.5	26.6	32.4	35.7
Col. 5	18.5	26.6	32.4	35.7
Col. 6	20.9	26.6	32.4	35.7

Source: NERA estimates; for detailed explanation see text.

TABLE A-2.—ESTIMATED MAXIMUM EXPENDITURS[1] ON COAL CONVERSION THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS ("DO-NOTHING OPTION RULED OUT; ALLOWING FOR COAL REPLACEMENT OF EXISTING UNITS)[2]

[1977 dollars per kilowatt]

Life remaining after completing conversion (years)	Simple plan[3]			Full plan[3]		
	Coal at $25 ton per[4]	Coal at $30 per ton[5]	Coal at $35 per ton[5]	Coal at $25 per ton[4]	Coal at $30 per ton[5]	Coal at $35 per ton[5]
	(1)	(2)	(3)	(4)	(5)	(6)
Oil plant:						
5	$260.19	$176.07	$166.11	$292.72	$198.08	$186.87
10	421.76	285.40	269.26	474.48	321.07	302.91
15	522.05	353.25	333.27	587.30	397.41	374.93
20	584.36	395.42	373.06	657.40	444.85	419.69
25	623.00	421.56	397.73	700.88	474.26	447.44
30	647.02	437.82	413.07	727.90	492.55	464.69
Gas plant:						
5	260.19	176.07	166.11	292.72	198.08	186.87
10	421.76	385.40	269.26	474.48	321.07	302.91
15	522.05	353.25	333.27	587.30	397.41	374.93
20	584.36	395.42	373.06	657.40	444.85	419.69
25	623.00	521.56	397.73	700.88	474.26	447.44
30	647.02	437.82	413.07	727.90	492.55	464.69

[1] Maximum economic expenditure on coal conversion is defined as the present worth of fuel savings adjusted for investment tax credits of 10 percent in cols. (1), (2), and (3) and 20 percent in cols. (4), (5), and (6).
[2] See text and app. A for derivation of calculations and assumptions.
[3] Simple plan takes the price of oil at $13.59 per barrel and the price of natural gas at $2.25 per million cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3–$3.30 per million cubic feet.
[4] No scrubber necessary on conversions.
[5] Scrubber necessary on conversions.

Note.—The following running costs are assumed:

[In mills per kilowat-hour]

	New coal	Converted coal	Difference
Col. 1	13.6	12.5	−1.1
Col. 2	15.7	18.4	+2.7
Col. 3	17.75	20.9	+3.15
Col. 4	13.6	12.5	−1.1
Col. 5	13.6	12.5	−1.1
Col. 6	17.75	20.9	+3.15

Source: NERA estimates; for detailed explanation see text.

ESTIMATED MAXIMUM EXPENDITURE[1] ON COAL CONVERSION THAT WOULD BE ECONOMIC UNDER VARYING ASSUMPTIONS ("DO-NOTHING" OPTION RULED OUT; ALLOWING FOR NUCLEAR REPLACEMENT OF EXISTING UNITS)[2]

[1977 dollars per kilowatt]

Life remaining after completing conversion (years)	Simple plan[3]: Coal at $25 ton per[4] (1)	Simple plan[3]: Coal at $30 per ton[5] (2)	Simple plan[3]: Coal at $35 per ton[5] (3)	Full plan[3]: Coal at $25 per ton[4] (4)	Full plan[3]: Coal at $30 per ton[5] (5)	Full plan[3]: Coal at $35 per ton[5] (6)
Oil plant:						
5	$214.80	$84.22	$28.87	$241.70	$94.75	$32.48
10	348.24	136.51	46.79	391.77	153.58	52.64
15	431.10	168.97	57.92	484.92	190.09	65.16
20	482.50	189.14	64.83	542.81	212.78	72.94
25	514.40	201.65	69.12	578.70	226.85	77.96
30	534.24	209.42	71.79	601.02	235.60	80.76
Gas plant:						
5	214.80	84.22	28.87	241.70	94.75	32.48
10	348.24	136.51	46.79	391.77	153.58	52.64
15	431.10	168.97	57.92	484.92	190.09	65.16
20	482.50	189.14	64.83	542.81	212.78	72.94
25	514.40	201.65	69.12	578.70	226.85	77.76
30	534.24	209.42	71.79	601.02	235.60	80.76

[1] Maximum economic expenditure on coal conversion is defined as the present worth of fuel savings adjusted for investment tax credits of 10 percent in cols. (1), (2), and (3) and 20 percent in cols. (4), (5), and (6).

[2] See text and app. A for explanation and derivation of estimates. Nuclear capacity is assumed to cost $800 per kilowatt; other assumptions are discussed in text.

[3] Simple plan takes the price of oil at $13.50 per barrel and the price of natural gas at $2.25 per million cubic feet. Full plan reflects taxes on utility consumption of oil and gas; the price of oil is $15 per barrel and the price of natural gas is $3-$3.30 per million cubic feet.

[4] No scrubber necessary on conversions.

[5] Scrubber necessary on conversions.

Note.—The following running costs are assumed:

[In mills per kilowatt-hour]

	Nuclear	Converted coal	Difference
Col. 1	8	12.5	4.5
Col. 2	8	18.4	10.4
Col. 3	8	20.9	12.9
Col. 4	8	12.5	4.5
Col. 5	8	18.4	10.4
Col. 6	8	20.9	12.9

Source: NERA estimates; for detailed explanation see text.

The CHAIRMAN. Next, we will hear from Mr. Hans Tanzler, mayor of Jacksonville, speaking on behalf of Jacksonville; and Mr. Louis Austin, chairman of the board, Texas Utilities Inc.

STATEMENT OF HON. HANS TANZLER, MAYOR OF JACKSONVILLE, FLA.

Mr. TANZLER. Mr. Chairman, someone inquired this morning that things are so tight in Florida now that I could not get Florida Power & Light to even buy me breakfast this morning.

Also, Senator, if we have another winter as last year with the snows in Miami Beach, we will be looking for you in that swimming pool in Louisiana.

It could be very well asked why I am appearing here as the mayor of the city of Jacksonville. As I mentioned, we have one of the largest municipally owned utilities in the United States and, I suppose, since you have already heard from very highly technically trained professionals in the field, perhaps it would be an interesting change of pace to hear from one of those long-suffering veterans of the front line trenches of urban America who has served as mayor of this city of almost 600,000 people for the last 10 years.

As such, it has been a warm, human experience and I appreciate serving my constituents.

I am not an engineer; I am a lawyer by profession. My experience in this field of energy has come from being chief executive of our utility for the past few years. I have watched the difficulties of it, and of course, whatever difficulties we have are immediate. The buck stops at my desk.

I would like to make an observation that our utility alone burns almost 1 million barrels of oil a month. It is almost all imported oil. I welcome the opportunity to appear before this august group, for the purpose of speaking out on that portion of the energy plan. As I understand it, Senators, it is calling for a $1.50 barrel of oil, escalating upward over a period of time for inflation, as an incentive.

This incentive aspect is primarily what I would like to speak to. It is an incentive, I suppose, for utilities in my State and for the rest of the country to conserve in the consumption of oil and second to convert. We have already heard testimony this morning as to some other method of producing that.

I am here to tell you, Senators, that we have already had our incentive in Florida. That incentive occurred back in October of 1973 when the price of oil jumped from $2.69 a barrel for our utilities to almost $12 inside of 90 days. That was like the old proverbial Missouri mule getting hit on the nose by a 2-by-4. That got our attention.

Needless to say, that was a disaster as far as our electric bills were concerned. A fuel oil adjustment charge was then necessary to be placed on our bills. We put it in a separate column to show the sudden increase of fuel.

Our fuel adjustment charge exceeds now about 120 percent the original bill itself. People, as you know, have difficulty in understanding that since we own the utility, why in God's name does the price have to go up like that? And needless to say in those years while serving as mayor, I have seen my own authority members, who served without compensation from within the business community, hold a public hearing to increase rates to cover the increased price of fuel, literally be accosted, threatened with bodily harm, publicly cursed and hung in effigy by people who felt that they were just ripping off the public by raising those prices.

I have had to go through the picket lines to get to my office at city hall. Of course, the only solution to that would be to drill out in the parking lot in front of city hall or take Saudi Arabia, neither one of which was very feasible.

But there is a communication gap. I think you can appreciate just how difficult it is for the people to understand this, but we went through that proposition, and we fought every step of the way for every battle that was necessary, one right after another, to hold down the price of the electricity, knowing that it had already gone through the ceiling.

We fought the import tax. At the time, we were heavily dependent on the importation of foreign oil because it was the most convenient and the cheapest. It was not a bad decision 5 years ago. It certainly became one in 1973.

We were told if we imported foreign oil, we would be taxed for it. We said, well, we will not import it. Give us some domestic oil. They said, we do not have any, but if you still want to change, you have to get permission. You have to find another source. In the meantime, we will tax you until you do.

We finally won that battle and got out from under that one. But, then we had to fight EPA on the use of cleaner fuels. They were constantly going up on their air pollution standards and down on the sulfur content of oil, and they were constantly monitoring and so forth.

Any time the OPEC nations met and then considered the possible price increase we, like you and most others in this country, screamed with outrage and anguish over the possibility of yet another insensitive increase in the price of oil, which translated into further hurt for the American economy and the consumers of electricity throughout this Nation.

With that history of battles—some won, some lost—I am here to say that it is hard for me to understand, truthfully and candidly, how it ever could be that it would be necessary for me to appear before this august group on the Hill and the Capitol of this great Nation to ask this Government of the United States not to do the very thing that we were decrying the OPEC nations for doing—that is, increasing the price of electricity to our consumers.

I realize that these are strong words and I apologize if they appear that way, but they are born of frustration, as I already pointed out, in the difficulties that we have had.

I am going to get back to the main thrust of what I was saying. If there needs to be an incentive, we have that incentive. We have evidence of the incentive of the increased price of oil—the doubling and quadrupling of the price has already worked.

The consumers of Florida have already conserved, since 1973, approximately 20 percent in their consumption. They have tightened their belt, and the reason they have was not an extra tax or anything else. It was just the total price, and the cost of electricity. Everybody cut back. They cut back to the point where maybe refrigerators are not even doing an adequate job of keeping food for a low-income family.

The utilities throughout Florida committed themselves to conversion to another method—conversion being primarily, as you have already heard this morning, replacement. Today, almost 100 percent of the electricity generated by the utilities in Florida is from oil-fired plants. By 1986, we will reduce that dependency on oil by 30 percent, and that will be at the cost of some $7 billion to the State of Florida. Obviously the consumers in the State of Florida are going to be the ones who are going to somehow put up the front money in the form of rates to make that possible.

If it were possible to completely convert all the utilities in Florida, we understand, it would cost in the neighborhood of $20 billion, but we know now that over half of those are simply not convertible. They are located in downtown and areas where there is not the land to do it even if it were remotely possible.

There are no oil-fired units being constructed in Florida now. There have not been for the past 4 years.

The city of Jacksonville is going to coal. Our next 600-megawatt unit will be coal and it is going to cost us a half-billion dollars.

To add to all of these costs, which are continually going to escalate, required simply to provide the power that we need—and we are on the edge right now—to add to all of these costs, the possibility of considering an extra tax is just absolutely inconceivable. It would cost the consumers of Florida, as I understand the projections, almost $2 billion over the 1983 to 1990 period.

We do not need it. It is not going to help us. We will be paying $260 million in 1983 to do the very thing that we are doing just as fast as we can and we can certainly use those dollars on the front end to make it possible.

If you put it on us now and say we will give it back to you later, then it has to go into the rates somehow. It goes into rates that I am saying already make it difficult to find dollars just for changing to other energy sources, much more difficult to find them at a time we need them—which is now.

I do not have to tell you that those who pay in every State, but particularly in Florida find that rate increases bring on additional hardships. I think everybody recognizes Florida is a retirement State and there are an awful lot of elderly people there, an inordinate number and percentage, and a lot of them are retirees on fixed income. Also, because we are a very popular State and a fast-growing State, a lot of people are unemployed.

When those bills throughout the State of Florida doubled and tripled and quadrupled, I held open house every Wednesday afternoon in the mayor's office. I wish you could see the little old ladies in tennis shoes pull out their knotted handkerchief, unfold a corner of it, and count out the pennies and the quarters and the half-dollars and say, that is all I have. All I have burned is my refrigerator, and they are going to cut it off because I owe them $25. I cannot pay it.

In Florida we have to say that we are doing the best we can. We do not own an oilfield. We are doing everything we can to hold the price down.

But I am saying—if we have to put a tax on top of what we are already doing, after the battles we have fought, you will hear the greatest cry of anguish you have heard since the Civil War coming out of the State of Florida in protest of the absurdity of what we are faced with.

I would like to make the suggestion, something concrete, if I could. It has already been made.

One thing could be done, other than giving us money at the front end since that is what we really need to do what we know we have to do. The Congress of the United States could do something about permitting.

My director of the Jacksonville Electric Authority tells me if you had the dollars today to go ahead and build this coal-fired unit that we are in the process of going toward, and made application this year, he said he could not get the application approved, even to break ground, until 1980, and then there is the construction time.

If there is almost a 50-percent increase in the total construction time, there has to be at least a 50-percent increase in cost when you consider the inflationary factors and what that means to the cost of putting it in the ground. We need to do a streamlined, simplified and coordinated job.

I have a great fear, having gone through the problems with a sewer plant holding 15 public hearings in 5 years. We ended up right where we started and the cost of the plant is now twice as much as it was when I started. Having fought before hearings on the air pollution standards of the State and the Environmental Protection Agency, my biggest fear is not that we are going to build coal plants, but when we start on this 600 megawatt plant, finally get through all the hurdles and get it built 6 or 7 years down the road, and when we get ready to cut the ribbon, fire it up and have a big ceremony, somebody will show up from the Environmental Protection Agency to hand us a ticket and say that is a beautiful plant, but you just cannot use it because something funny comes out of the stacks.

I know that sounds like I am being facetious but I have been down that road with that exact problem. We are not at a very tight level on our air pollution standards. We are monitoring it, and I hope, as we launch ourselves into this other direction, the technology is going to keep up with us so that when the time comes to cut that ribbon we will have been able to solve completely the environmental aspects and we can go forward.

Finally, let me discuss the discrimination aspect that already has been mentioned, the inequities. Certainly, Florida suffers from the inequity and the discrimination of it all. We do not have coal. We do not have geothermal. Yes, we are looking forward to these exotic other methods—alternative methods that are discussed such as solar. But, as they say down South, the Sun does not even shine all the time in Florida, as we saw last year with the snow. And wind power, that is great. The only time that would really work in Florida is when we have a hurricane and that is going to be geared up a little higher than it needs to be for the rest of the year, I hope.

The problem is that we simply happen to be located where we naturally moved toward oil, and with the proximity of Venezuela and other places, we moved toward importation. Because of that, it is estimated that while we have 4 percent of the population in the United States, we would be paying 8 percent of the new user tax.

In closing, Senators, I appreciate the opportunity of your taking the time and letting me appear. In summary, the tax will not, in my opinion, or in the opinion of anyone from the State of Florida, in any way, shape or form be an incentive, encouragement, or help for us to get any faster down the road in the direction we are already going.

We are going there, we realize it, we are going to do it. In fact, to take the dollars away in taxes would be simply putting a stumbling block in our way. In fact, that would be a disincentive rather than an incentive toward the purpose, the laudatory purpose, for which it was designed to be.

It might have been 5 years ago, but now we do not need an incentive. We have got it.

We have hopes and dreams of being able to arrive at where we want to be—conversion and moving away from the dependence—and we have a hope, at least, of being able to do it. That is sort of a light at the end of the tunnel. It is a possibility, by simply adding just on top of it the straw that broke the camel's back, if you will, we will just be putting that light out at the end of the tunnel and putting the lights out for an awful lot of people throughout the State of Florida.

Senator, I thank you.

The CHAIRMAN. Thank you very much.

Mr. Austin?

STATEMENT OF LOUIS AUSTIN, CHAIRMAN OF THE BOARD, TEXAS UTILITIES CO.

Mr. AUSTIN. I appreciate the opportunity to comment on the Energy Tax Act of 1977. Since detailed information and figures are included in my written testimony, I will only summarize briefly.

You have a tremendously important responsibility in considering this legislation. I feel for you. You have a thankless job.

We are deeply concerned about certain provisions of the Energy Tax Act of 1977 because they discriminate against our customers and could have a greater impact on Texas than on any other State in the Nation. Our customers will bear the brunt of the tax burden. Yet, we cannot envision how these tax provisions could significantly help achieve the goals of the national energy plan. So please, do not pass this user tax. It simply is not needed.

This would not be a tax on our company; it would be a tax on our customers. Customers always pay for everything. We have never been able to repeal this basic law of economics for one good reason: The customer is the only one there. You know that, Mr. Chairman. The tax would fall on the shoulders of our customers.

Our existing generating units planned for peaking use cannot be converted to coal due to environmental and site constraints and economic in feasibility. Thus, the only alternative to the payment of this tax would be the replacement and early retirement of some 7 million kilowatts of useful gas/oil generating capability. This would require the investment of billions of dollars in new coal-fueled peaking units.

If you do not pass this tax, we can do a better job of what we really need to accomplish in this country—to make sure that the Nation has a firm supply of energy and that consumers get it at a fair price.

I think Senator Packwood said that we really have enough energy—we have coal and we have uranium. The way I put it, the good Lord really gave us two things: He gave us more coal and uranium than the Arabs have oil and he gave us creative minds. So, we have no geological reason or technical reason for not having enough energy.

The only reason we cannot use it is because of regulations that restrict, not encourage, its development and increase costs to our customers.

What is amazing to me now is that we are imposing more restrictive regulations to try to get out of the spot that regulations got us into. Please do not burden our customers with the added unnecessary costs of this tax.

The tax would provide no incentive to convert, as it is intended to do. It would simply be an unfair and onerous penalty levied upon our customers. It would increase rates without encouraging fuel conversion and could even impair out ability to carry out present conversion plans.

We must let the free market system function instead of passing more laws and regulations.

The mayor mentioned one example of this—people have started conserving. Mr. and Mrs. America do not need the Federal Government to tell them how to handle their pocketbook. They are going to conserve because the price is going up.

A second thing that has happened in the State of Texas, with the market system working, is that the drilling rigs are running because of the unregulated $2/billion Btu price. They would not have run at the federally controlled interstate price.

It is cost, not conspiracy, that is making fuel costs go up. We have our own gas pipeline system, drilling programs, and joint ventures to supply gas for our powerplants. We drill wells today that cost us $3 million that used to cost us $300,000, yet they produce no more gas.

We have one area where we drilled 27 wells. Twenty-one of them were dry holes, and the cost of the gas from the six producers—just for drilling and pipe—is $3 per million Btu.

The free market long ago dictated that industry and everybody go to alternate fuels. We started a long-range program to shift to Texas lignite and nuclear fuel 10 years ago. We started construction of our first lignite plant in 1968. Last year, about one-third of our generation was from lignite.

Now, even the small companies and other industries are looking for lignite and other alternate fuels.

Please let the market system work.

Adding more taxes that electric utilities would have to collect will not get any more energy. It would be better to tax the consumer directly. He would then know exactly what his cost of electric service was, and he would know exactly what his Government cost of service was.

I thank you for your attention and ask for your support in eliminating the inequities in the Energy Tax Act that would unjustly discriminate against our customers.

The CHAIRMAN. Thank you all very much, gentlemen. Are there any questions?

Senator PACKWOOD. I understand this user tax, the so-called rebate that you get if you indeed convert to coal, all you get is the rebate against the cost of the user tax. You cannot set it off, if your costs are greater than the user tax. You cannot offset it against your other income, is that right?

Mr. AUSTIN. That is right. If we did not convert peaking units, we would pay, during the years 1983 through 1990, $900 million in user taxes.

Senator PACKWOOD. Here is the point I am driving at. There was the statement in GAO's study on the administration's plan, which I think is wrong unless I misunderstand how this rebate works. You cannot be any better off under the rebate plan than you are now. You would get an investment tax credit now as you are moving toward coal, right?

Mr. AUSTIN. That is right.

Senator PACKWOOD. If you take the rebate on this money, you cannot get the investment tax credit?

Mr. AUSTIN. That is right.

Senator PACKWOOD. So if you pay a $3 user tax and you got $3 worth of investment, you can write it off against the user tax, but you are worse off because you do not get the investor tax credit.

Mr. AUSTIN. That is a decision that everybody has got to make. If this bill goes through, in our system, we would have to spend $6 billion to replace gas peaking units in order not to have those taxes.

Senator PACKWOOD. Is this statement in the GAO report right or wrong?

In summary, oil and gas users tax and the rebate investment tax credit have the following advantages.

It would encourage conversion to coal, mainly by decreasing the capital costs through the rebate investment tax credit mechanism.

I do not see how it decreases the cost. It seems to me you end up paying more under the present law, where you simply take your investment tax credit but do not have the fuel user tax.

Mr. AUSTIN. I have my taxman, Mr. John Turner. He studied this in more detail.

Senator PACKWOOD. Did you hear that statement that I just read from the GAO? I am not sure they are right. I am not saying you have to defend it. I do not understand how they make that statement.

Mr. TURNER. Senator, I do not know if I could defend the statement. To me, there is a disincentive in that the utility will lose the investment credit—I believe your statement was correct.

Senator PACKWOOD. If you invest $100 million now under the investment tax credit, in addition to whatever expenses you have, the investment tax credit against the income?

Mr. AUSTIN. Yes.

Senator PACKWOOD. Under the fuel conversion system, you pay the user tax. You can take 100 percent credit all right, only to the limit of your fuel user tax. You cannot take it beyond that, and you lose your investment tax credit.

Inevitably, you have to come out worse off than you are. I do not see how you could come out any better off, or where you can even break even from where you are now, as opposed to this fuel user tax. I do not see where the incentive is at all, as opposed to the present system.

Mr. TURNER. I agree.

Mr. AUSTIN. That is correct.

Senator PACKWOOD. I do not have any further questions.

The CHAIRMAN. Are there any further questions? Senator Roth?

Senator ROTH. No questions.

The CHAIRMAN. Senator Matsunaga?

Senator MATSUNAGA. Thank you, Mr. Chairman. Mayor Tanzler, I am sorry to hear that Florida's sunshine is worse than Hawaii's.

From the bleak picture that you paint, Mr. Mayor, I suppose after prospective tourists read about the conditions in Florida, they will all go to Hawaii and run into the same energy problems, because we in Hawaii find ourselves in a similar situation.

Fortunately, in Hawaii's case, the Congress has been wise enough, to exempt Hawaii from coal conversion.

But you grow a lot of sugarcane in Florida, too. Are you making any effort toward the use of biomass? We used to throw sugarcane bagasse as garbage into the sea; but when EPA came along and prohibited the dumping of bagasse into the sea, the sugar industry started thinking of ways to use it. Now sugarcane bagasse is burned to produce electricity, and industry is doing it very effectively.

Are you involved in any sort of biomass program?

Mr. TANZLER. Senator, I think that every utility of any size in Florida is already examining very closely all of the possible advantages of considering that. I know our own utility is. I know several of them around the State of Florida are looking at it very closely.

The feedback that we get that considers the quality of that biomass that is available to us, particularly in solid waste, is of the scope, as I understand it, of the size that, particularly in the solid waste area in Jacksonville, that if we took all of the garbage that we use now for landfill and produced over a year period, that we could fire up our generators for less than 30 days with it, so that there is simply not that much when we are talking about a million barrels a month to produce our capacity of 2,100 megawatts.

We would like to use it. There might be some advantage to it, but apparently it is not cost-effective, at least according to our people, at the present time.

Senator MATSUNAGA. The problem that the administration and, in cooperation with the administration, the Congress are trying to resolve is the possible depletion of domestic oil, and the increased import of foreign oil. In just the last few years, the import of oil has increased from about 20 percent to 50 percent.

Imported oil will cost us about a $42 billion deficit in our balance of trade; we are trying to resolve this problem. We must first cut back the use of petroleum so that we will not have to import so much; and second develop alternate sources of energy so that we will not need to depend upon oil so much and not be concerned about depletion of domestic reserves.

Fortunately, in Hawaii we can look to geothermal and solar energy, but I see by your statement that you do not have too much sunshine in Florida. That's too bad. We have a lot of sunshine in Hawaii, but you do not need much sunshine to take advantage of the inexhaustible supply of energy coming from the sun.

Mr. TANZLER. We are hoping and praying that the technology will rapidly arrive and will keep up with our demands so that we might see the day that Florida would be the energy producer of the country. We do have a lot of sunshine in Florida, but it is not 365.

I hope and pray that we will get to that point. We are using it for hot water and things of that nature, but solar reflectors for actually producing electricity as examined in attempts to do that, you can air-condition a single house. We have not arrived there except with a reflector big enough to take in this whole building.

Senator MATSUNAGA. But you can use solar energy for heating water. I have testimony from my constituents in Hawaii, telling me that they have saved anywhere from 25 to 40 percent on their monthly electric bills by merely converting to solar heating of water.

Mr. TANZLER. Absolutely.

Senator MATSUNAGA. This is an area where your State and my State can really exploit.

Mr. TANZLER. We are moving toward that. From a utilities standpoint, for the generation of electricity, we have not arrived at that. For home heating, for home needs for water, or maybe a building or something of this nature, through building codes and through requirements, we are trying to urge and expedite decisions along that line, in spite of the increased costs and the slow recovery basis.

All the steps the Federal Government has taken along these lines in the way of the tax credit, I think that is a big incentive. According to our figures, it is in the neighborhood of 20 percent of anybody's electric bill is to heat the water. If they turn it down a little bit and so forth—we had our Mayor's Energy Office in Jacksonville trying to tell the people you do not need the hot water heaters turned up so high so that when you turn it on you have to mix it with cold water to be able to use it.

That is where we are in our country. A lot of people could get by with a lot of reduction in the overall temperature of the water itself.

As far as generating for electricity, we are simply not there yet. It is oil or it is nuclear. That is where we are at the present time. We need help, the utilities do, in the lag time of the licensing and the permitting and the processing that then caused the cost of the construction to continue to escalate.

Senator MATSUNAGA. Mayor Tanzler, I am inclined to agree with you. Where conversion is impossible because you have no available coal, just as we do not in Hawaii, you ought not to be taxed for the oil that you have no alternative but to use. And we need to make some definite adjustments in the administration's proposal.

Mr. Austin, I might say we are not here to tax, tax, tax, because if we do that, we tax our own people. As Senator Long, the chairman of this committee, once told me when I was still a student at Harvard Law School and I came lobbying for Hawaiian statehood, and he was opposed to it, and after I had made my pitch to him, he told me,-

"Young man, you all must remember that a U.S. Senator is primarily interested in two things: One, to be elected; two, to be reelected." [Laughter.]

When we impose a tax, we do remember that we must tax our own constituents too, and they elect and reelect us.

The CHAIRMAN. If I just might interject, you know, Senator Matsunaga took that advice.

Mr. AUSTIN. We think that solar has some applications. In fact, I have a solar heater myself. They have had so much trouble with them—the fellow I bought it from said he would put one in his house, first. I said, you do that, and he has had so much trouble with it, he has not installed mine yet. Unfortunately, I paid him for it back in February.

We also have three solar houses that we are running experimentally in our system.

Let me talk a little bit about the balance of payments because of imported oil. I know you have a particular problem there.

We took the Btu value of imported oil and converted that to Btu's and tons of coal and put that into coal production and took the average man-days—in other words, if we quit importing oil and mine coal, we could help our unemployment program because that is about 300,000 jobs just in coal mines alone, not counting the jobs of dragline equipment people, railroad people, and coal slurry pipeline people.

Some way or another, we can do this, happily. We cannot meet all the EPA standards and all of the other standards. You just passed the strip-mining bill and I have here the intermediate rules and procedures for opening of a strip mine. May I read something?

We have been handling explosives safely for years. Now, according to these new rules, I have to make sure that the guy handling explosives is in good physical condition and not addicted to intoxicants, narcotics, or similar types of drugs.

I say to you, I am going to have to get drunk on Saturday night if I am going to have to put up with all this stuff.

We do have a problem with oil imports. It is the problem of payments. We have to stop passing new regulations so we can use the domestic energy supplies we have.

Senator MATSUNAGA. Just so long as you get drunk on Saturday nights, when you don't handle explosives.

I can understand your frustration.

Mr. AUSTIN. We are frustrated as all hell. I know some of you are, too.

Senator MATSUNAGA. There is no joking about it. Maybe someday we will get to resolve these things to satisfy everyone.

Thank you, Mr. Chairman.

The CHAIRMAN. Mr. Austin, I once, for some reason that escapes me now, volunteered to take over the demolition team at a military base, and my impression of the kind of personnel who were willing to voluntarily handle that fool stuff was that all of them were a little bit nutty, including me. One would think that anybody in his right mind would stay away from the fool stuff. When they now say in one of the regulations that you have to see to it that the fellow who is handling the demolitions does not drink even on Saturday night, that is going a little far.

Everybody I could find around that base who was willing to voluntarily go out there and fool around with these demolitions, every one of them, for some reason or another, did not have the usual reason for wanting to be a demolition man. I got the opportunity to hold that job when the previous demolition officer blew himself up with his own explosives. So you would think it is a good business to stay out of ordinarily. Now I see that not only are you going to have to find somebody willing to handle explosives, but you are going to have to see that he has a good moral background.

Mr. TANZLER. If I could make one last observation, the startup of this tax, as I understand it now, is 1983 and escalating at whatever the cost of living might indicate, CPI, inflation factors built into it from 1979. It ignores two things. It seems to ignore whatever conservation efforts that have been made.

Second, it ignores whatever commitment has been made to convert. We have done both. We are moving and shifting toward a lesser dependency.

We would pay that tax for over 2 years, although we are now committed and saying we are going to do it.

We know what our needs are. We are way ahead of you, we have already started. Why should we pay a tax for almost 2½ years when we are already going to do the very thing that the plan wants us to accomplish, and I think this is pretty difficult for Florida and pretty difficult for the Nation.

The CHAIRMAN. Of course, the sheaf of papers that Mr. Austin held up was about 2½ inches thick. If contains new regulations that the Government has dreamed up under the new law Congress just passed to provide him with that many more problems he has to contend with in trying to mine coal and to use the coal in his utility plants.

The point you made very well, Mr. Mayor—and also the previous witnesses—is that utilities have done everything that they can to comply. If for some reason completely beyond their control, such as 1,000 pages of new regulations from the EPA, they are unable to comply, it is very unfair to punish them or punish their customers, because none of them are able to do something that the Government would like for them to do. Or, in the case that they have already complied, it is even more unreasonable. They have done everything that they have been asked to do and they are going to be penalized by a punitive tax anyway.

I think you have made a good case, and so did the previous witnesses on that point.

Senator PACKWOOD. Is there anybody here in the audience from the FEA or the administration? [No response.]

Let me read this statement in the record. I am going to ask the administration—I am reading from the GAO report—as to the ultimate savings in oil and gas because of utilities constructed. In coal fire generation, however, the question of regulatory requirements would be somewhat academic, because the trend is already away from oil and gas. This is evident from data of the Federal Power Commission for 1977: 48 oil, 12 gas-fired plants are expected to come on line. In 1985, six oil and no gas-fired plants are projected.

I am going to ask the administration, is there any evidence of what additional savings, just on utilities—I am not talking about other businesses—what additional savings they project from this user tax that are not otherwise going to be realized anyway in the direction that the utilities are going?

Mr. AUSTIN. That is a good question.

The CHAIRMAN. Thank you very much, gentlemen.

[The prepared statements of Mr. Tanzler and Mr. Austin follow:]

STATEMENT OF MAYOR HANS G. TANZLER, JR.

As Mayor of the Consolidated City of Jacksonville, Fla, for the past 10 years and thus the Chief Executive of one of the largest municipally owned utilities in the United States, I have been vitally involved with the entire energy picture and particularly its impact upon the public inasmuch as I, too, am an elected official.

I have testified before Congress in years past as well as before regional national task forces on the subject of energy and I have served as President of the National League of Cities just last year. In spite of this front line experience, I do not hold myself out as an "energy expert"; I am not an engineer, I am a lawyer. Due to my experience, I like to think that I have a better than average understanding of the intricacies of this energy question and I feel comfortable in saying I have a unique understanding of the public's attitude in this area, inasmuch as I have had to confront the slings and arrows of outraged citizenry including picket lines around City Hall demanding that we do the impossible, i.e. reduce electric rates.

As a result of the above and foregoing, I have been asked by the utilities of the State of Florida, both private and public, to respond to the energy plan now before this committee and its effect on the utilities of the State and the customers of those utilities.

I welcomed the opportunity to appear before this august committee to speak out against that portion of the energy plan which calls for a tax by the Federal Government of $1.50 per barrel (escalating upwards) for all utilities in the country as "incentive" for them to convert to coal. I am here to tell you that for such a proposal to be seriously considered as an "incentive" is not only "a day late and a dollar short", but is 4 years late and several hundred billion dollars short. I am here to tell you that when fuel oil went from $2.69 per barrel in 1973 to $12.00 in January of 1974, that was our incentive . . . that was all the incentive anybody could ever want. That 500 percent increase was, and is, an incentive to find some other method of production of power. Our utility like all of the rest of the utilities in the State of Florida, had no way of absorbing that type of impact, but had to pass the increased cost along to our consumers. Typical household electric bills doubled and tripled. They understandably reduced their consumption and thus reduced the revenues we needed for conversion construction. We desperately fought for every penny of tax relief possible; first was a tax on the importation of foreign oil that our State was so unfortunately dependent upon.

We also fought for every fraction of a percentile of relief we could manage to obtain before the air pollution environmental regulatory agencies of the state and Federal Government. Whenever the OPEC nations met and considered any possible further increases in the price of oil, we joined forces with our representatives in Washington in condemning such thoughtless insensitive highway robbery, etc. It is, therefore, absolutely inconceivable to me, that it should be necessary to appear before this committee to protest the very action by our own government that we have previously blamed on those greedy OPEC nations. You want us to reduce consumption . . . we have. You want us to shift to coal . . . we are! We need to be helped not hurt.

Perhaps some of you find my strong words offensive, and if so I hope that you will accept them only as words borne of frustration . . . and entirely too long in the front line trenches of urban America. Candidly, the purpose of this plan is a most worthy one. The idea of converting to coal, thus lessening our dependence on foreign oil is laudatory, and I find no fault whatsoever in any method that would realistically provide an "incentive" where one does not now exist. Such a proposal as a tax increase to provide an incentive seems to ignore the fact that those of us in Florida and other states like us have already been provided that incentive. As proof of the results of that incentive, the consumers in Florida sacrificed and reduced their electric consumption by approximately 20 percent and our utilities made a seven billion commitment to construct alternate methods of producing power. How many states can match that sacrifice in life style? The entire purpose of this plan was for all practical matters, accomplished 4 years ago in our state.

I know of no utility in Florida that is planning to build another oil fired generator. On the contrary, by 1986 (only 3 years after the effective date of the tax) the State of Florida will have already shifted from almost 100 percent oil to almost 30 percent coal/nuclear, all without any urging from the Federal Government or further "incentives" in the form of a tax.

It should be pointed out at this time that the biggest and most crying need for utilities is not what we should do, or whether we should do it, but where we will find the money.

Keep in mind that the shift from oil to coal, as I am sure this committee recognizes is fraught with all sorts of problems not all of which can solve . . . not the least of which is an environmental air pollution stack emission scrubber problem. Not the least of which is the additional land required for storage of the huge mountain of stockpiles of coal, as well as the mountains of ash, the settling ponds of the scrubbers, etc., etc. Add to this the fact that the existing oil fired boilers cannot be cost effectively converted but require entirely new boilers 30 to 40 percent larger, constructed independent of existing boilers, requiring almost a 2 year shutdown outage of existing boilers during the transition; requiring approximately 3 years for delivery of new coal boilers (very conservative estimate) and assuming the availability to 100 rail cars to be tied up, coming and going each day from even as small as a 450 megawatt plant. Obviously a great number of existing plants, for all practical purposes, are simply not capable of being converted.

In spite of these intrepidations the utilities of Florida have already committed themselves to a program of shifting to the construction of coal fired units and nuclear to cover all future growth needs . . . Needs which have been seriously neglected for the past four years. The problem in our State, the nation's fastest growing, is for the utilities to find the estimated seven billion dollars needed to meet our commitments through 1986 for new plant construction. In Jacksonville alone with only a 2,100 megawatt total production capacity, it is going to cost us in excess of a half billion dollars to construct even a 600 megawatt coal unit. Obviously our utility, like all the rest of the utilities in Florida faced with all these enormous capital outlays, will have to look to our customers to provide us with the revenue.

These dollars are going to have to come out of the tattered pocketbook of the electric utility customers of Florida, an inordinate percentage of which are not only elderly retirees on fixed incomes, but actually unemployed. These increases unquestionably not only have a stifling effect on economic growth, jobs, etc., but will cause screams of anguish the likes of which have not been heard since the Civil War.

Let us realistically examine this energy plan as it affects the people of Florida.

1. We are already committed to a program of constructing all new power plants—coal or nuclear power. These commitments will result in a 30 percent reduction in our current dependency on oil through the year 1986. The cost to the utilities of Florida and thus the citizens of Florida is in excess of $7 billion.

2. If we in Florida were to be required to convert all of our existing oil fired utilities to coal for instance, the estimated cost would be in excess of $20 billion . . . all of this without producing 1 additional kilowatt hour of electricity.

And to think that these problems we are now inevitably faced with do not even take into consideration the possibility of another $1.50 escalating to $2.32 a barrel increase by 1989 . . . a little "bonus" from the Federal Government to help us along. We suggest you look around and consider such a "bonus" or "incentive" to some states that need it . . . that do not have a proven record of sacrifice and conversion. Once again, we have got the incentive now . . . what we need is help. We need help with the seven billion dollars needed to fund our existing commitment to construct new coal and nuclear plants, not an incentive tax bill for another 2 billion on top of everything else.

I recognize that money is tight for everyone, and I'd like to suggest at least one method of help not involving cash. One of the biggest ways we could be helped in this regard is to streamline, simplify, coordinate and standardize licensing and permitting procedures necessary for the construction of any plant. Time, dollars and oil could be saved.

It is unconscionable in a time when every month's delay means a different and higher cost of construction, to hear the Director of our utility state that if we had the money to begin construction today of additional coal fired boilers, and if our licensing/permitting application sailed through and we had no difficulties and no unusual protests evolving from the environmental impact study . . . it would still take until sometime in 1980 to get final state and federal approval. Frankly, my biggest fear is that as we launch headlong into this commitment to convert to coal, and struggle with the rate increases necessary to finance that commitment, and hold the inevitable countless public hearings, etc., etc., that seven to eight years from now after we have overcome all the hurdles and we finally fire up the boilers, someone representing the Environmental Protection Agency is going to run up and hand us a citation injunction telling us the quality of our air will not absorb another fraction of a percentile of degradation, according to that agency's regulations. "Nice plant. but you can't use it."

I can't pass up the opportunity to capitalize on an extremely popular word of the day—"discrimination" . . . I can't help but feel that Florida (and certainly some other states) are being discriminated against simply because we happen to produce our electric power by oil. We are being discriminated against in Florida because we have no coal fields . . . we are being discriminated against because we have no mountainous lakes for harnessing the hydro-electric capability . . . and needless to say, we have no geo-thermal possibilities either. Thus Florida through no fault of its own, with a population representing only 4 percent of the nation would be required to pay approximately 8 percent of the proposed tax. Prayerfully, we look for the day that solar or wind or tide or hydrogen production of electricity will be a scientific technological reality. . . . But, frankly, I'm a little skeptical . . . this past winter proved that even in the Sunshine State, the "sun don't shine all the time", nor does the wind blow all the time. Our State, in spite of a complex cooperative grid system, is already realizing brownout incidents due to the slowdown in plant construction, coupled with an increase of 1.8 million in population over the last ten years. Our needs are to be moving forward with the construction of additional production capacity now! Capacity that reduces our dependency on oil. Realistically there are only two such options open to us, coal and nuclear. Certainly we urgently need a national commitment to fund the research and development necessary to bring the day closer that these other possible alternatives can become a technological reality, but, until that day, we cannot afford, in my opinion, to leave a single stone unturned. Certainly continuing research in the area of breeder reactors as well as the simplification, standardization, etc. of the construction and licensing of nuclear plants is essential.

In closing and in summary, let me simply say that if this body imposes upon the utility consumers of the State of Florida and the nation this proposed tax for the purpose of providing an "incentive" for them to convert to coal or nuclear production, then there is no question in my mind (or those knowledgeable in the field of production of electricity in Florida) that you will not be providing us with an incentive at all, but you will be placing in our paths an almost insurmountable roadblock . . . a dis-incentive . . . to accomplish that which we are already committed to accomplish. How? By making already hard to find dollars just much harder to find.

We have at least a hope of being able to accomplish converting to coal or nuclear; at best it's a light at the end of the tunnel; if you pass this bill and further make prices higher, and make it that much more difficult for us to finance our construction commitments you will have effectively turned out the lights at the end of the tunnel and the lights of the people of Florida.

Statement of T. L. Austin, Jr.

I am T. L. Austin, Jr., Chairman of the Board of Texas Utilities Company. The three electric utility companies in the Texas Utilities Company System—Dallas Power & Light Company, Texas Electric Service Company and Texas Power &

Light Company—serve about four million people in a 75,000 square mile area of north-central, east and west Texas. This is about one-third of the area and one-third of the population of the State.

We are deeply concerned about certain provisions of the Energy Tax Act of 1977 because they discriminate against our customers and could have a greater impact on Texas than on any other state in the nation. Our customers will bear the brunt of the tax burden. Yet, we cannot envision how these tax provisions could significantly help achieve the goals of the National Energy Plan.

We wholeheartedly agree with the administration's objective to reduce the use of natural gas and oil for the generation of electric energy and to replace them with coal and nuclear fuels. In fact, we began an orderly long-range program to use these alternate fuels ten years ago—well before any widespread recognition of impending energy shortages.

In 1968, we started construction of our first power plant to use a long overlooked Texas resource, lignite coal. When our first lignite unit began service at the end of 1971, our System's generation was 100 percent natural gas with small quantities of oil used for standby purposes. By the time the Texas Railroad Commission acted in 1975 to reduce the use of natural gas as a boiler fuel, more than one-fourth of our generation was from lignite.

We now have a program at the State level which is realistic and will phase out the use of natural gas . . .

Without disrupting our economy;

Without any loss of jobs;

Without threatening the supply of electricity;

Without imposing unreasonable costs on customers; and

Without the unnecessary expense and red tape of Federal controls.

The Texas Railroad Commission has ordered a 10 percent reduction in the use of natural gas as a boiler fuel by 1981 and a 25 percent reduction by 1985. In the Texas Utilities Company System, we plan to reduce this usage from that during the base year of 1974 by some 35 percent by 1981 and 65 percent by 1985.

Our customers are already being "taxed" because of our dependence on natural gas. First, because they must pay the high cost of capital to build new power plants to use coal and nuclear fuels. Second, they have over the years paid the higher cost of new intrastate gas supplies not priced artificially low by Federal regulation. Our customers must continue to pay these high capital costs until we have virtually rebuilt our System to use alternate fuels. Under our present plan, natural gas and oil will be used for only 25 percent of our generation by 1985.

Now, these proposals would place an added cost burden on our customers, at the very time they are strapped with the higher costs of conversion and fuel. The user tax, like the cost of all legislation and regulations enacted by Congress, would fall on the shoulders of the consumer. Under the Energy Tax Act, our use of natural gas and oil (even though its use would continue to decline and be primarily for peaking purposes) would result in our customers paying an estimated $900 million in user taxes from 1983 through 1990.

Our existing generating units planned for peaking use cannot be converted to coal due to environmental and site constraints and economic infeasibility. Thus, the only alternative to the payment of this tax would be the replacement and early retirement of some seven million kilowatts of useful gas/oil generating capability. This would require the investment of billions of dollars in new coal-fueled peaking units. Based on the best available information, our engineers estimate that this cost would be more than six billion dollars. User taxes during the conversion period would still amount to some $200 million—so, the estimated reduction in user taxes, $700 million, certainly provides little relief compared with the investment of additional billions of dollars. Furthermore, it is extremely doubtful that the additional capital necessary for this conversion of peaking units could be raised in view of the enormous financial requirements we already face.

The tax would provide no incentive to convert, as it is intended to do. It would simply be an unfair and onerous penalty levied upon our customers. It would increase rates without encouraging fuel conversion and could even impair our ability to carry out present conversion plans.

Because these peaking units cannot be feasibly converted, we believe that the administrator would allow them to continue using gas by granting an exemption under Title I of the Bill. This Bill should also include an exemption from the user tax under such circumstances, and we urge that it be amended to specifically provide for such an exemption. To leave this determination to two individuals—the adminstratior and the Secretary of Treasury—could easily result in arbitrary or inequitable taxation that could be prevented by a clearly defined statutory provision in the Bill.

This amendment would help to mitigate the hardship that would be imposed on our customers. But, only major changes in the entire proposed energy program can keep it from becoming an administrative nightmare.

The Congress seems intent on solving energy problems by hastily creating a bureaucratic monster "which", The Wall Street Journal says, "threatens to bury every electric utility in the nation in red tape, stopping the expansion of electrical generating capacity."

The editor of a Texas newspaper summed it up this way: "In years past, we have worried about government taking over control of our oil and gas industry and all other forms of energy. Perhaps the time has come when our worst fears have been realized."

We in the electric utility industry can get our job done—if we are just left alone to do it. We need your help, but not unnecessary interference. We desperately need a national energy policy and program, but it should be . . .

One that is practical—not political;

One that is based on reason—not on more regulation; and

One that relies on common sense—not on Federal controls.

The proposed legislation ignores the basic solution to the nation's energy problems—incentive for increased production through the function of a free marketplace. These problems can only be compounded by the increased Federal intervention, taxation, red tape and restrictions proliferated by this Act and other legislation contained in the proposed National Energy Plan.

The user tax provision to which we object so strongly is but one example of this. To compel our customers, who have borne the cost of a conversion program started ten years ago to reduce our use of natural gas, to either pay $900 million of user taxes or support an added capital cost of more than six billion dollars (and still incur $200 million in user taxes) in punitive and discriminatory and, we believe, certainly not the desire of the Congress. Subjecting our customers to this excessive economic penalty, for what would be a relatively insignificant fuel savings, would not achieve the intended purpose of this Bill.

I thank you for your attention and ask for your support in eliminating the inequities in the Energy Tax Act that would unjustly discriminate against our customers.

The CHAIRMAN. Next, we will call Mr. D. D. Jordan, president and chief executive officer, Houston Power & Light Co.

STATEMENT OF DON. D. JORDAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER, HOUSTON LIGHTING & POWER CO., HOUSTON, TEX.

Mr. JORDAN. Thank you, Mr. Chairman.

Mr. Chairman, you and your committee have listened very attentively to a number of issues as they affect electric utility companies under this bill. As the fifth speaker on the program, I do not think it is necessary to repeat many of the general statements you have heard, which I concur with, but I think it would be important for the committee to see specifically how this bill might affect one utility company in the south, Houston Lighting & Power Co.

I have some charts I would like to show you in a few minutes and when I get to that; I would appreciate the opportunity to do it.

In general, I would say that we support the view of the NEA and the goals of the NEA, the National Energy Act. However, we have two very major and strong pieces of opposition.

I would like to tell you that the Houston Lighting & Power Co. is a company that covers a 5,600 mile area. It covers only 2 percent of the State's area in Texas but serves 23 percent of the population.

It is a highly industrialized area, providing service to approximately 12 percent of the Nation's petroleum productivity, and 40 percent of the petrochemical productivity. Our economy is strong, the growth of Houston continues to move along and the population growth in 1977 will be approximately 100,000 new people.

Houston Lighting & Power Co. is now the fifth largest electric utility company, individual company, in this country in terms of kilowatt hours sold. In 1977, 100 percent of those kilowatt hours were produced by burning natural gas. We represent a very appropriate example for you to take in reviewing the effects of this bill.

As I said, we do support the overall objective of the bill. However, the two exceptions we have to it apply first to time, because we believe and contend that under the current program, we are moving as fast as we can move when you consider the capital availability and our ability to attract it.

This is supported by FPC testimony provided before the House and provided by Bernard Chew, Chief of the Division of Power Analysis of the Bureau of Power, FPC, when he testified on March 28, 1977, and said, in his view, the electric utility companies in the country were moving as rapidly as they could toward the goal of moving away from oil and gas and toward coal and nuclear.

Second, we believe that the oil and gas use tax clearly impedes and does not assist in the problem of conversion. Utilities with large dependence on natural gas and oil as we have which also operate in a growth area cannot convert these units fast enough to avoid the tax and simply cannot reclaim enough of the tax through rebates. Because of the situation we are in, we are one of four electric utility companies reviewed in detail by the administration prior to the time they took their strong position on some of the issues in this bill.

Not only did we come to Washington on many occasions to review our numbers with them, but they sent their consultants to Houston, and we went over many print-outs on many occasions to review the numbers.

As you well know, numbers can sometimes differ and you have to boil it down to a point where you finally agree on a certain set of conditions. All of that was done, and we believe our numbers now clearly reflect agreement with the administration in terms of what the effect will be on Houston Lighting & Power Co.

We represent to you today that our numbers are accurate and that we would defend them in any debate against anybody in the administration. I believe that debate will not be forthcoming.

I would like to show you these charts, if I may, Mr. Chairman——

Senator PACKWOOD. If I understand, while I read this testimony, you do not get any of this tax credit for replacing a facility, only if you convert?

Mr. JORDAN. According to this testimony, you will get some rebate only on the basis of retiring units. The initial position of the administration was that you would get a rebate on the basis of $125 per kilowatt for those units that were either retired or moved down into a peaking mode; a peaking mode being defined as units being operated 1,500 full load hours or less each year.

The Ways and Means Committee reviewed that and they made some modification to it, giving a larger rebate. The numbers I am going to show you now are based on that House bill.

The green portion of the chart, Mr. Chairman, indicates to you the corporate plan of Houston Lighting & Power. We moved in this direction long before the bill came out and support the idea of moving away from oil and gas, but expect to do it in a way that we can, in fact, afford to do.

This represents an investment, if we did what is shown in green, of $8.349 billion over this period of time, from 1977 to 1990. The current total capital investment in Houston Lighting & Power Co. is $2.6 billion.

In case you might believe that we prepared a set of charts to be impressive and slanted all the numbers in our favor, let me tell you how it was done. This was based on a 4.8 percent growth rate for our area over that time. In the past 14 years, we have averaged 9.9 percent growth.

We recognize we are going to have some conservation in our area and hope that that does come about. We also know that Houston seems to be an area that attracts people, it attracts businesses and also attracts indusry. I am deathly afraid the 4.8 percent growth rate may not be great enough for our part of the country.

Also, it is calculated on a 12-percent reserve margin.

I believe that it is very optimistic to think you can operate on a 12 percent reserve margin. It is perhaps possible if you consider operating natural gas units, which we now are but not when we convert to coal. This chart does contemplate the addition of 10 coal-fired units for about 5,300 megawatts and two nuclear units totaling 2,000 megawatts.

There will be no additional oil or gas units constructed by Houston Lighting & Power Co. system during this time, or any time in the future.

When you contemplate operating that kind of a system on 12 percent, you could be told by anybody in the business it is a dangerously low number. Consequently, we have reduced our plan down to very marginal levels for the purpose of determining investment.

In order to finance the proposed construction program, our financial advisor tells us we would have to have rate increases during that period of $1.1 billion in order to maintain a return on capital investment of about 15 percent. I also remind you that no electric utility company, perhaps with the exception of one or two in this country, are earning 15 percent on common equity.

The ability to do this construction job is very risky.

The CHAIRMAN. You say before taxes?

Mr. JORDAN. Yes. We are in a position now where our company is earning 14.5 percent return on common equity. The return on investment for utility companies operates in a cycle. You can get a rate increase, you move it up. As time goes by, that return moves down. We happen to be riding at the crest of the cycle right now.

Our capital people tell us that in order to do the job outlined in green, we would have to have these things fall into place to the point where we could get the type of rate increase we requested.

Current revenues for our company are $920 million. The rate increases during that period of time attributable to the construction program alone, would more than double the current revenues of the company.

The program we designed was applied to the tax program that came out of the House. We were paying oil and gas use tax of $1.25 billion between 1983 and 1990 and we would be able to recover by rebates, $388 million. It would put us in a loss position of $860 million.

We gave similar testimony to the House on several occasions and the issue was reviewed in detail with the administration. The day before the ad hoc committee met, the administration, refuting these numbers, came forward with one and a half pages of written material and said that we would, in fact, get all of our tax back simply by adding two more 950 megawatt machines.

We have shown in orange what this addition would do to the capital investment in our company. It would involve the addition of $1.722 billion over and above the $8.6 billion already planned.

I believe the House passed the oil and gas use tax with the clear idea that each utility was going to get back the total amount of money they put into the tax. I say that because of the colloquy that took place between Congressman Eckhardt and the chairman of the Ways and Means Committee, Congressman Ullman. They discussed in detail the oil and gas use tax, whether or not it was intended as an incentive to help the utilities do the job, or whether it was, in fact, a method to raise taxes for the use of the Federal Government.

I would call your attention to the August 5th Congressional Record, page HA-8791, which indicates the clear intention of the bill was to facilitate the conversion. It was not to develop a new Federal tax source, and there was clear intention to exempt electric utility companies from that tax, if, in fact, they are not able to get it back.

You can read the language on that page, and I believe it would be interesting to you.

With that background, then, we moved ahead to develop what our position would be if we could add two 950-megawatt coal units. You can see that the problem is not really solved, because after 1982, we have to raise $750 million a year for capital investment in a very small business. Given the rate increase records of the public utility commissions of this country, it will be virtually an impossible task to undertake.

This second chart shows you the gas and oil use tax that would apply to us as the bill passed the House. In 1983, for example, we would have to pay $212 million.

So from the period of time from 1983 to 1990, while we would pay $1.12 billion in taxes, we would reclaim under this bill just over $600 million in rebates which gives us an unrecovered tax of $425, almost $426. million.

It is interesting to note in the comments of Dr. Schlesinger earlier this week, that this represented no problem. That there would, in fact, be an additional incentive provided for utility companies if the Congress went back to the original plan of the administration and provided only $125 a kilowatt rebate for units retired or reduced to peaking.

If you were to do that, it would clearly have the effect of eliminating rebates that our company could otherwise get. While the tax would remain the same, the amount of the rebate would only be $234 million, which would provide us with a net loss in taxes of $888 million during that period of time.

We conclude, from looking at these numbers, that very clearly in the case of an electric utility company that has large obligations to burn natural gas and oil in a growth area, there is no way under the program to get the entire tax amount back in rebates.

In addition, there is no way to carry these annual tax deficits forward. When you lose, for example, in 1985 $150 million, these tax losses cannot be recovered in future years. A rebate loss in any single year is lost forever.

Mr. Chairman, we would say to you that under the plan, electric utility companies clearly are impeded from making these conversions, rather than helped, as the administration indicates their goal to be. But if you were to be able to cure this problem and provide rebates for the total amount of the tax, some additional difficulties clearly would exist.

In the first place, electric utilities cannot pass through this tax under the fuel adjustment clause. You recognize in 1983, we would have a $212 million tax. Our total profits last year were $112 million. It would be very difficult to assume the tax under any given set of conditions. The bill simply must be structured so that if the tax is to exist, it will be passed through in the fuel adjustment clause.

So we would make three recommendations here this morning.

First, we do not believe that the tax rebate system is needed. We think that the utility companies are clearly moving as rapidly as their financial capability will allow them to move to get this job done. But, if, in fact, the Senate, in its wisdom, can see no other way other than to impose some tax, then I think you must insist that the tax works the way it is represented to work. Look into it in enough detail to know its effect before it is passed.

The language contained in the colloquy which I included in my remarks, which have been filed for the record, between Chairman Ullman and Congressman Eckhardt certainly should be made a part of the bill. It is necessary to very clearly indicate to everyone that it is not the intent of this Congress to impose additional taxes that cannot be reclaimed through the rebate.

You have some additional possibilities, I think, to correct some of these deficiencies if you phase the taxes in at a later date and in a smaller amount.

I believe you should give attention to this, only if you find in good conscience that you cannot eliminate the tax rebate system. It serves no good purpose for the country or the utilities that, ostensibly, the administration is trying to help.

If you agree to pass the oil and gas use tax through the fuel adjustment clause, because only in that way will the utilities be able to handle it, then the rebates must be addressed. They must be paid back promptly, and must be paid directly to the utility rather than the utility commissions, as is now contained in the bill.

The politics involved in commission regulation would often deny the customer the benefit of his tax dollars that have been collected and held in escrow for future use for capital investment.

I would be willing to answer any questions, Mr. Chairman.

The CHAIRMAN. Thank you very much.

Senator Packwood?

Senator PACKWOOD. No questions.

The CHAIRMAN. Senator Matsunaga?

Senator MATSUNAGA. No questions.

The CHAIRMAN. Thank you very much, sir.

[The prepared statement of Mr. Jordan follows:]

STATEMENT OF DON D. JORDAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER, HOUSTON LIGHTING AND POWER CO.

Our company provides electric service to a 5,600 square mile area on the upper Texas Gulf Coast, serving approximately 2 percent of the land area of Texas and 23 percent of the state's population. The area is highly industrialized. Our customers refine 12 percent of the Nation's petroleum products, produce 40 percent of the Nation's petrochemicals, and serve the Nation's market for steel and other highly diversified finished products. They also supply fuels to the Midwest and East, rubber to Akron and Detroit, plastics to New England, textiles to Georgia and the Carolinas, and agricultural chemicals to the Atlantic States. Large quantities of oil and natural gas are processed in the region and it is a center for worldwide oil and gas exploration and production activities. The economy of the Houston area is strong and our population growth in 1977 will exceed 100.000.

Mr. Chairman, we support the objectives chosen by the President for our national energy policy. Particularly, we support the objective of decreasing and ultimately eliminating the use of natural gas as a boiler fuel. It is an objective that we began working towards long before the National Energy Act was announced. We have not begun construction of a new gas fired boiler since 1968 and all future generating plants will be fueled either by coal or nuclear. In the interim, however, 100 percent of our generating capability of over 10,000 megawatts is dependent on natural gas, with oil as an alternate fuel for a portion of this capacity. Replacement of our existing capacity with coal and nuclear, as well as expanding our capacity to meet future growth, will impose substantial capital costs on our customers and stockholders. In recognition of these problems, Houston Lighting & Power Co. was selected by the administration as one of four utilities in the country for extensive analysis of the impact of the National Energy Act. We have worked closely with the administration and have attempted to provide them whatever information and data they requested. From analysis of our own company, (see appendix A), we have concluded that the largest single problem confronting utilities faced with rapid area growth and massive expenditures for moving away from oil and gas is that of accumulating the necessary capital to accomplish both. Although the tax proposals advocated by the administration were ostensibly designed to encourage this accumulation,[1] H.R. 8444, as passed by the House, not only does not encourage it, in the case of Houston Lighting & Power, it operates to discourage it for the following reasons:

1. The logistics of the user tax/rebate mechanism do not operate when it is necessary to completely replace existing facilities; they function when only modifications are necessary to convert existing facilities to other fuels.

2. The regulatory aspects of the Bill may force a utility to take funds out of capital to pay user taxes, further deteriorating the utility's ability to raise the necessary capital to finance replacement expenditures.

[1] "The tax measures are designed to raise the cost of gas and oil to industrial and utility users; and to provide positive incentives for conversion to other sources of energy." National energy plan, p. 65.

LOGISTICS OF THE USER TAX/REBATE MECHANISM

H.R. 8444 imposes a tax on the use of both oil and gas by electric utilities beginning in 1983. Although utilities will be allowed to carry forward qualifying investment expenditures made between now and 1983 to offset tax liabilities beginning in 1983, rebates are to be allowed only to the extent that existing oil- and gas-fired facilities are replaced or phased down. H.R. 8444, as adopted by the House, provides that the amount of the rebate shall be the cost of the new boiler and related facilities. In the case of our company, this cost ranges from $300 ot $350 per kilowatt, and this figure has been supplied to the administration. Between 1983 and 1990, H. L. & P. would pay a total of $1.12 billion in oil and gas use taxes and receive rebates of only $696 million, resulting in a net loss of $426 million in unrecovered taxes. (See appendix B.) In his written testimony before the committee on Monday, Secretary Schlesinger proposed that rebates of user taxes to electric utilities be limited to $125 per kilowatt, regardless of the cost of replacement. If this proposal is adopted, the net amount of taxes unrecovered by H. L. & P. jumps to nearly $882 million. Loss of either of these large sums would constitute an added cost burden on our customers, and a tremendous obstacle to the fuel conversion program we are carrying out.

Mr. Chairman, the reason we will lose so much in unrecovered taxes is due to our great current dependence on natural gas, and the fact that we are unable to make substantial retirements of existing generating capacity due to the rapid growth of electrical requirements in our service area. HL&P currently uses gas for 100 percent of its generating capability, and consumed approximately 460 Bcf in the last 12 months. For the most part, utilities saving overall system dependency on natural gas are located in the producing states. However, because federally regulated interstate gas was held at artificially low prices, many utilities with alternate fuel capability in other regions of the country have used large quantities. During 1976 some 656.3 Bcf of gas purchased under interruptible contracts was burned under utility boilers in states that are net importers of natural gas.[2]

Many of these utilities have in past years switched coal-burning facilities to gas and oil, but still possess the necessary sites or facilities for burning coal, such as railroad spurs, loading docks and storage capacity. However, we constructed our facilities to burn gas. Although half of them have been converted to continuous oil burning capability, none of them can be converted to burn coal; they must be replaced. Unfortunately, this is a distinction the Bill fails to recognize.

Mr. Chairman, we strongly recommend that H.R. 8444 be modified to take into account the heavy financial burdens faced by the customers of utilities which must replace their existing facilities. We propose that an exemption procedure from the user taxes be specifically provided for those utilities which can demonstrate that the net effect of imposition of the oil and gas use taxes would be to increase consumer rates without facilitating conversion from the use of oil and natural gas and would impair the utility's ability to accomplish such conversion.[3]

We feel it essential that such an exemption procedure exist in order to provide relief to those utilities unable to avoid heavy losses under the tax program because all of their existing facilities must be replaced, and which, because of the faculty operation of the tax/rebate mechanism incorporated in the bill, are unable to recover in full the taxes paid. This can occur even though qualified conversion expenditures exceed the amount of the taxes. This results when area growth renders it impossible to phase down or retire existing generating units without incurring a serious hazard to the reliability of service. We emphasize

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[2] FPC news, vol. 10, No. 2, Jan. 14, 1977, at table 11; FPC news release No. 23271, July 12, 1977 at table 11.

[3] Specifically we propose that a new subsection (c) be added to section 4993 that provides:

SPECIAL UTILITY RECLASSIFICATION

"The Secretary shall prescribe by regulations a procedure under which he shall classify the use of oil or natural gas by a regulated public utility (the principal activity of which is the production of electricity for sale) in the exempt use category if he determines that the imposition of the tax would have the net effect of increasing consumer rates without facilitating conversion from the use of oil and natural gas as a fuel and would impair the utility's ability to accomplish such conversion."

Identical language is contained in the report accompanying H.R. 8444 as adopted by the House Ad Hoc Committee on Energy. (See Rept. No. 95-543, volume I, at page 32.) The intent of this language was explained in greater detail in a colloquy between Mr. Eckhardt and Mr. Ullman during floor debate on H.R. 8444. (See Congressional Record, Aug. 5, 1977, at H8791-H8792.)

that this proposal would not grant an outright exemption to any utility. It does provide a failsafe mechanism of insuring that the taxes are accomplishing their stated objective of encouraging the replacement of oil and gas with coal and other fuels.

You also may wish to consider a more specific alternative of phasing in the tax on oil and gas at a lower amount than that currently specified in the scheduled tier 3 use category of section 2041. As appendix B illustrates, although we face the heaviest burden of gas taxes in 1983 through 1986, our ability to make commensurately significant replacements and phasedowns (and thus eligibility for rebates) does not occur at the same time because of the rapid growth in demand in our service area. This is the case despite the bill's advance certification procedure and provision for carrying forward qualified expenditures.

Mr. Chairman, we are prepared to offer any assistance you, the members of the committee, and staff may desire in developing such proposals. However, we reiterate our request that a reclassification exemption procedure be contained in the bill in addition to any specific modifications the committee may decide to make. Such a procedure, to be triggered only under certain defined conditions and designed to alleviate the logistical problems associated with the operation of the tax/rebate mechanism that we have mentioned today, would offer assurance that the objective of the user tax to encourage replacement of oil and natural gas facilities will in fact be met.

FLOWTHROUGHS OF USER TAXES AND REBATES

Regulatory aspects of H.R. 8444 may force utilities to use their captial funds to pay the user taxes, thus further impairing their ability to raise the additional necessary capital to finance their fuel conversion programs. Although not included in the administration's proposal, the bill currently prohibits a utility from passing on to its customers through the automatic adjustment clause any increased costs due to the imposition of the oil and gas user taxes. (Section 514 of title I). At the same time it leaves to the discretion of state regulatory bodies the extent to which rebates will be passed through to customers of utilities. In the case of H.L. & P. the annual amount of the tax consistently exceeds the profit of the company, thereby making it impossbile for the taxes to be absorbed.

If we are to meet the obligations of even our existing corporate program to replace oil and gas facilities (illustrated in appendix A), which was planned and embarked upon prior to the national energy plan, rate increases totalling nearly $1.1 billion would be required between 1977 and 1990. This is an amount substantially above the company's current annual revenues, and would result in our rates, which have already escalated sharply, more than doubling between now and 1990. Past experience with state public utility commissions throughout the country indicates serious, if not insurmountable, difficulties in securing rate increases of this magnitude. To force the company to request rate increases of an additional amount of $1.12 billion to pay user taxes will place both us in and the regulator in an unbearable situation.

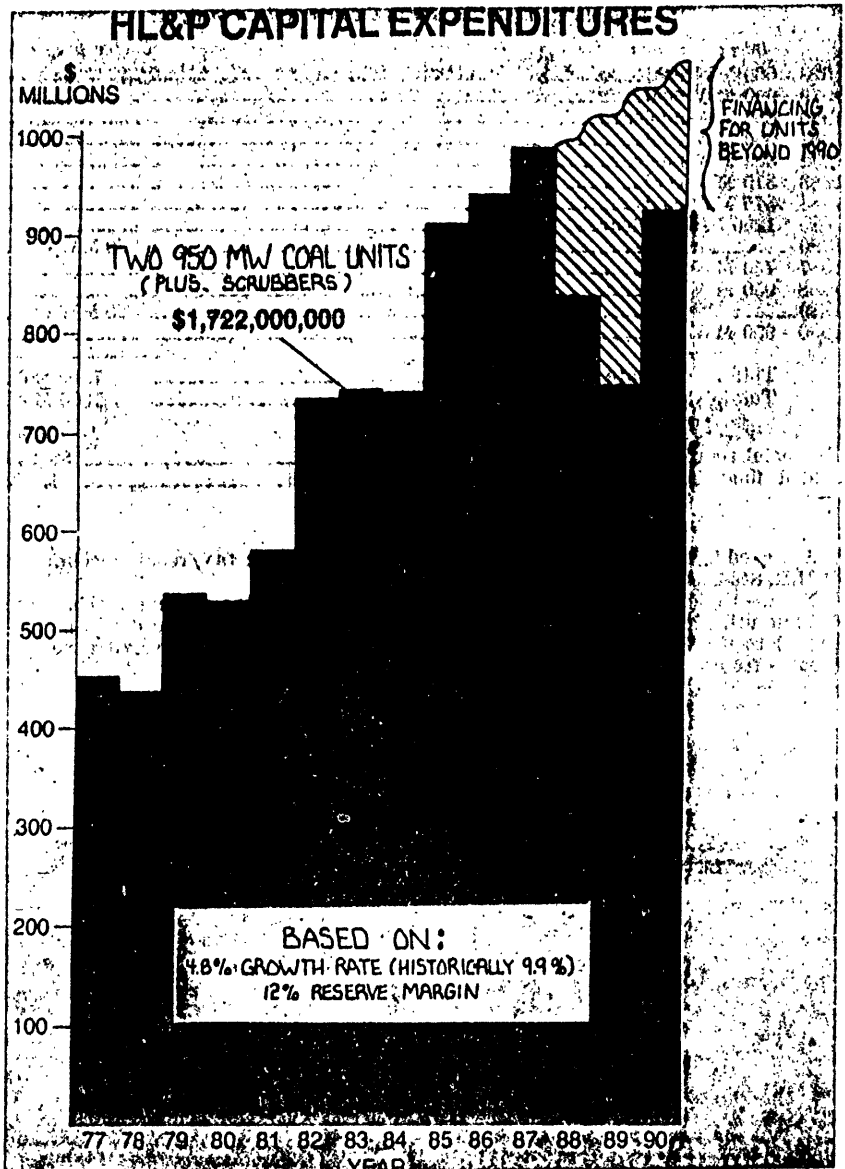
An additional important consideration is the handling of rebates accruing to utilities through completion of qualifying energy projects. The bill should clearly delineate the handling of such rebates in a manner which will assure their being available to facilitate the utility's fuel conversion program.[4] We urge the committee to include subsection (d) of section 4997 in the bill, as originally adopted by the Ways and Means Committee, in order that the tax rebate program will be more likely to function as intended.

Mr. Chairman, thank you for the opportunity to appear before you today. I shall try to answer any questions you or the members may have.

APPENDIX A

Attached is a chart illustrating the capital required to finance H.L. & P.'s existing corporate program of replacing existing facilities with facilities designed to use coal and nuclear fuels. Also shown is the additional capital necessary to comply with the regulatory requirements of the National Energy Act that natural gas be eliminated by 1990, except for peaking purposes between 1990 and 1995. An attached table indicates the additional generating capacity required to comply with this regulatory deadline.

[4] The authority of the Congress to determine who shall derive the benefits of a particular tax preference has been judicially recognized by the Supreme Court in *F.P.C. v. Memphis Light, Gas and Water Division*, (411 U.S. 458, 1973).


HL&P CAPITAL EXPENDITURES
$ MILLIONS
1000
900
800
700
600
500
400
300
200
100
TWO 950 MW COAL UNITS
(PLUS. SCRUBBERS)
$1,722,000,000
FINANCING FOR UNITS BEYOND 1990
BASED ON:
4.8% GROWTH RATE (HISTORICALLY 9.9%)
12% RESERVE MARGIN
77 78 79 80 81 82 83 84 85 86 87 88 89 90
YEAR

1978–90 generating additions and construction budgets

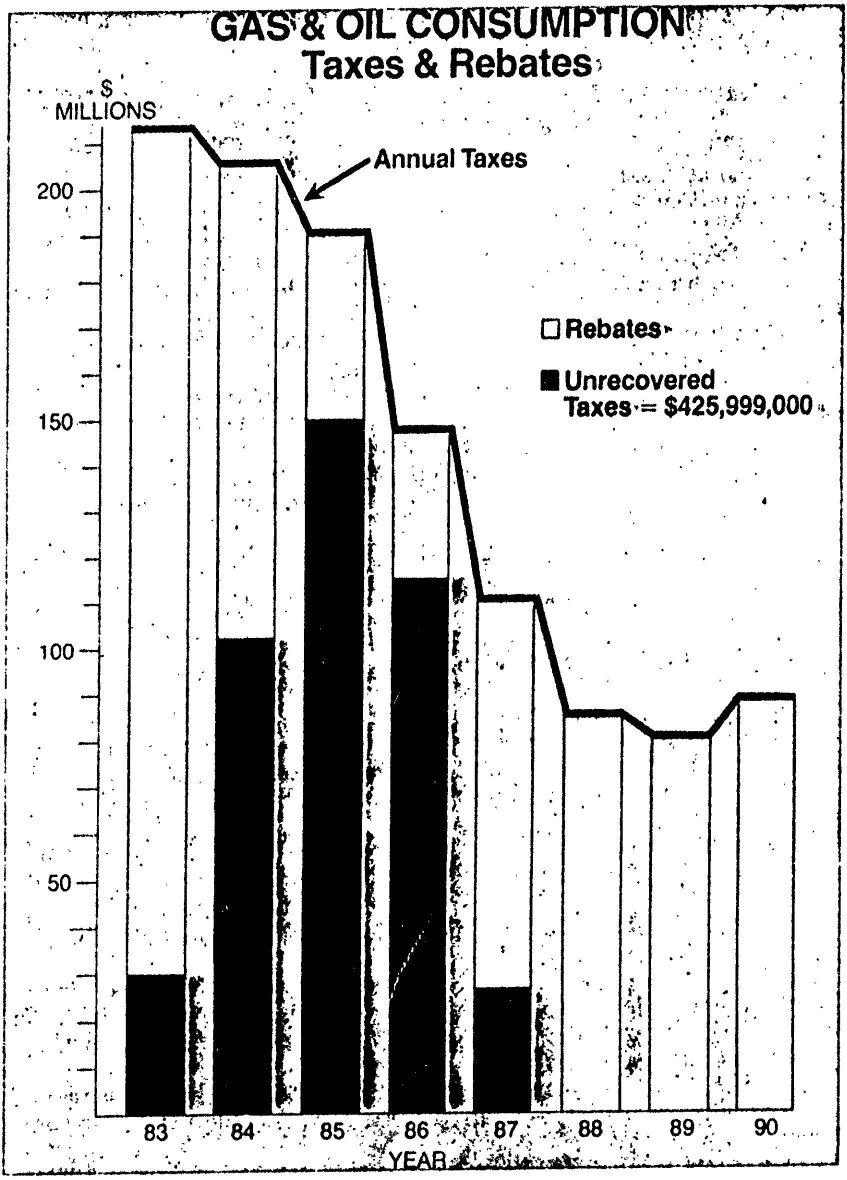
	Corporate plan	Carter program
1978	660 MW coal	
1979	660 MW coal	
1980	385 MW nuclear	
1981	600 MW coal	
1982	385 MW nuclear	
1983	375 MW coal	
1984	375 MW coal	
1985	1200 MW nuclear	
1986		950 MW coal.
1987	750 MW coal	
1988	950 MW coal	
1989		950 MW coal.
1990	950 MW coal	
	Total, corporate plan	7290 MW.
	Total, Carter program	1900 MW.

	Billion
Financial requirements 13-year corporate program	$8.349
Added financial requirements National Energy Act	1.722

APPENDIX B

Attached is a chart illustrating the operating of the user tax/rebate mechanism of H.R. 8444, as passed by the House.

NOTE.—Under Secretary Schlesinger's proposal to limit the amount of rebates to electric utilities to $125 per kilowatt of capacity retired or phased down, as presented to the Senate Finance Committee, the amount of unrecovered taxes increases from $425,999,000 to $881,773,000.



GAS & OIL CONSUMPTION
Taxes & Rebates
$ MILLIONS
200
150
100
50
Annual Taxes
Rebates
Unrecovered Taxes = $425,999,000
83
84
85
86
87
88
89
90
YEAR

The CHAIRMAN. Next, we will call Mr. William H. Coldiron, executive vice president, Montana Power Co.

STATEMENT OF WILLIAM H. COLDIRON, EXECUTIVE VICE PRESIDENT, MONTANA POWER CO.

Mr. COLDIRON. Mr. Chairman, members of the committee. I feel like a skunk in the congregation here, because I want to talk about a problem on the gas side of our business, not on the electric side of the business.

Also, I feel a little out of place because all of the previous witnesses have been from the sun belt and I come from the northern part of the frost belt.

The burden of my submission is to say that we are a company that is in a surplus position for gas. About half of our gas goes to industrial customers. Those customers are a cross section of American business, generally. They are mining, smelting, refining in the nonferrous metal industries, papermills, forest products, cement.

Those companies have already encountered a very substantial increase in the cost of gas because 70 percent of our gas comes from Canada.

If the oil and gas users tax is passed, its avowed purpose is to drive these customers off the gas systems of the country. If that happens, which it will happen if the tax is passed, it is going to throw the entire burden of the existing plant and production and transmission of gas onto the shoulders of the residential customers.

This is going to cause a very substantial increase in the cost of gas to be borne by those customers.

I think that it has been pointed out here that the gas supply situation is such that it can change very rapidly. Many of these industries have come on to use gas. They will have substantial costs, capital costs, to convert.

Once the customers are lost, they are going to be lost for a long time, or they are going to have to be ordered to come back to gas. We do not think that this is going to make much additional gas available. We think that it is going to throw an additional burden onto the gas consumers in this country.

We do not think that this problem is unique to the Montana Power Co. or all gas companies are faced with this, those particularly in Senator Packwood's area, which we are particularly familiar with.

Thank you very much.

The CHAIRMAN. Let me get one thing straight. You have a source of gas from Canada which is assured for a considerable period of time, do you?

Mr. COLDIRON. Yes. We have licenses that start expiring in 1985 to 1993.

The CHAIRMAN. Is it an inefficient use of that gas to use it to generate electrical power and then use that electrical power to heat the home? It is far more efficient to pipe gas in and burn it inside. You get about three times as much useful energy inside the house that way as you do by generating it and sending it on the wires, do you not?

Mr. COLDIRON. Yes. That is the correct rule of thumb that we use. We generate no electricity with gas. We are a hydro and coal company, 50–50.

The CHAIRMAN. I see. Do you not think for the most efficient use of gas, rather than using hydropower for heat, would it not be more efficient to use natural gas for heating inside the home?

Mr. COLDIRON. No question about that; because of the increase in the cost of gas, we have found that the new home heating customers are going to electricity, even though it is a less efficient use of our energy resources. I am sure I can get some argument from some of the electric people in the audience on that question.

The CHAIRMAN. I know something about that, I think. I have heard the argument before. Are you saying that they ought to continue to use gas for household heating?

Mr. COLDIRON. Yes, sir, absolutely. We are trying to sell gas in our area.

The CHAIRMAN. If you have the gas available to you—and that is Canadian gas we are talking about—if you have a contract and they are delivering it, everything I know makes me think it is an inefficient use of energy to use the gas for something else and to use hydropower to make electricity to heat the home.

Mr. COLDIRON. It appears to us that way. Thank you.

The CHAIRMAN. Senator Packwood?

Senator PACKWOOD. The whole premise of the administration's program is we are running out of gas and oil and before we do—and I hope we have some conclusion on that one, one way or the other—if the premise is right, what should be the incentive, the inducement, the coercion, call it what you want, to cause users of gas and oil to convert to coal and some other source?

Mr. COLDIRON. I think the marketplace will take care of it, if we do not try to change the forces of the marketplace through taxes or unreasonable regulation.

Senator PACKWOOD. It will take care of it in the sense that if the premise is correct that we will run out of oil and gas the market will force us to coal and something else?

Mr. COLDIRON. I had some question on whether or not, on a temporary basis, there is no question there is a shortage of gas. In our area we have a surplus. I am sure oil down here has a surplus position at the present time, contrary to what it was a few years ago.

The CHAIRMAN. How do you suggest we could prevent people from using hydro, to make them use gas? How would you urge us to do that?

Mr. COLDIRON. Putting a tax on industrial customers will not do it.

The CHAIRMAN. Do the opposite from this bill?

Mr. COLDIRON. The opposite.

The CHAIRMAN. I think you are right. Thank you very much.

[The prepared statement of Mr. Coldiron follows:]

STATEMENT OF WILLIAM H. COLDIRON, EXECUTIVE VICE PRESIDENT OF THE MONTANA POWER CO.

Like most gas systems in the United States, The Montana Power Company's system sells a substantial portion, about 43 percent, of its gas to interruptible industrial customers.

Montana Power gets about 70 percent of its gas supply from Canada. That country has as a matter of government policy, increased the border price for gas until it is now substantially the same as the world price for oil. This has resulted in an increase in gas prices to Montana Power's industrial customers of over 300 percent. If the Oil and Gas Consumption Taxes provided in H.R. 6831 are enacted, these industrial customers will certainly convert from gas to another fuel.

If interruptible industrial customers convert to other fuels, the fixed charges and operating expenses now paid by such customers will fall on the residential and commercial customers. Gas rates to residential customers have been increased by almost 100 percent and to impose these additional costs on them would be inequitable and contrary to the public interest.

New residential customers are electing to use electricity for house heat, even where gas is available, because of national publicity about gas shortages and the very substantial increases in gas rates on Montana Power's gas system. This is an inefficient use of energy.

Conversion by industrial gas users to some other fuel will not make additional gas available to Montana Power's residential customer since Canadian export licenses will expire before gas now available can be used.

STATEMENT

My name is William H. Coldiron. I am executive vice president of The Montana Power Company, Butte, Montana.

Montana Power is a combination gas and electric company serving directly or indirectly approximately 125,000 gas customers and approximately 205,000 electric customers in the western two-thirds of the State of Montana. In the area where Montana Power serves gas there has been a market saturation in excess of 95 percent and until recently almost 100 percent of the house heating was served by natural gas. Montana Power's gas system is an isolated system not interconnected with any other gas system other than with our Canadian suppliers.

We would like to point out to the Committee the adverse effect which the Oil and Gas Consumption Taxes provided in H.R. 6831 will have on residential and commercial gas consumers. It is the stated purpose of the Oil and Gas Consumption Taxes to encourage the conversion to coal or other fuel by large industrial users of oil and gas. These conversions would be brought about by placing a tax on the industrial use of gas, which will cause the cost of gas to the industrial user to be approximately the same as the cost of distillate.

The Montana Power Company's gas system is more or less typical of most gas systems in the United States, with 43 percent of its total gas volume being sold to interruptible industrial customers. We think there is no question that the increasing of the cost of gas to such customers through taxation will cause them to convert to other fuels.

We have some experience in the area of substantial increases in gas costs because some 70 percent of our gas comes from Canada. Canada, as a national policy, has increased the border price of gas progressively in the last three years until it has reached approximately the world price of oil on a BTU basis. This has resulted in an increase in the cost of Canadian gas to The Montana Power Company of about 700 percent. Because we have some production of our own in the State of Montana which is substantially cheaper than the Canadian gas, and because the Public Service Commission of Montana has not allowed us to pass through to our residential and commercial customers all of the increases in the cost of Canadian gas, we have been able to hold the cost of gas to our residential and commercial customers somewhat below the cost of Canadian gas at the border. However, because the price of gas to our industrial customers has been increased by 312 percent in the last three years, some of our industrial customers have converted to coal or other fuels or have indicated that they are considering the conversion from gas to another energy source. If the Oil and Gas Consumption Tax proposed in H.R. 6831 should be enacted, these industrial customers will have no choice from an economic point of view but to convert from gas to some other fuel. This, of course, is the intent of the tax. If the interruptible industrial customers convert to another fuel the fixed costs of the gas production, transmission and disribution plant and the operating costs, which are now paid by the interruptible industrial customers, will fall on the shoulders of the residential and commercial customers. Our calculations show that our residential customers are paying an average of $1.72 per MCF for gas and that if no other increases in costs are considered, other than the loss to the system of the interruptible industrial customers, the cost of gas will increase to $2.28 or 33 percent. If additional costs which are already being incurred by the Company are added to this, it will result in an increase in cost of gas to the average residential customer of $2.66 per MCF or an increase of 57 percent from the present costs. When the other additional costs for gas that are built into H.R. 6831 are considered, it is obvious that the cost to our residential customers will go up even more. To add an increase in costs of 57 percent to our residential customers who have within the last 3 years suffered increase in gas costs of 87 percent per MCF, it is obvious that the burden which our residential customers are asked to pay is completely inequitable. Therefore, we do not believe that the Oil and Gas Consumption Taxes on industrial gas consumption should be enacted.

The builders of new homes in our service area since the very rapid and substantial increases in the costs of residential gas has occurred have refused to install gas heating even though gas is available and is cheaper than alternative forms of fuels. Because of the national publicity concerning gas shortages and because of the 87 percent of increase in the costs of gas to residential customers in the last 3 years, the number of new homes being heated with electricity instead of gas has grown by about four times on the Montana Power Company system. Our sister utility to the west, Washington Water Power Company, finds that over 90 percent of the new homes in their service area are electing electric heat over gas heat even though natural gas is available. If there is a further increase in the price of gas to residential customers, which will certainly be the case if the Oil and Gas Consumption Taxes are enacted, more people will turn to electricity for house heating. This is, indeed, an ironic result from an energy bill which is reportedly designed to conserve energy. Gas home heating is a more efficient use of energy than electric heating and is cheaper in our service area. Therefore, it would appear that any tax which would result in an inequitable cost to residential customers and will cause the builders of new homes to install a less efficient fuel would not be in the public interest.

Causing industrial gas customers to convert to other fuels will not in the long run make additional gas available to residential and commercial customers on the Montana Power gas system. Seventy percent of our gas supplies comes from Canada under export licenses which will expire beginning in 1985. If the gas authorized for export under these licenses is not exported during the term of the licenses, it will revert to being available for domestic supply in Canada. If the gas requirements on the Montana Power system are cut in approximately half because of the loss of industrial customers, some Canadian gas now available to our customers will be lost.

The CHAIRMAN. Now, next we will call Mr. R. Sherman, president and chief executive, EBASCO Services and also, Mr. Henry Wheeler, consultant, Foster, Wheeler.

STATEMENT OF R. SHERMAN, PRESIDENT AND CHIEF EXECUTIVE, EBASCO SERVICES, INC.

Mr. SHERMAN. Thank you, gentlemen. My story will be very short. It just involves the resources that would be required for the electric utility industry to put itself in a position to afford the cost of these use taxes.

The organization which I represent is primarily involved in the design and construction of electric generating facilities in the United States and elsewhere in the world. We have been in this business for over 70 years.

In addition, of course, to the resources that would be required to accomplish this, we recognize that there are a lot of other physical limitations to the conversion of, or substitution of, facilities from oil and gas to coal-fired units. You would have the space limitations on many of the sites, the environmental problems in many of the areas, the requirements for coal storage, coal transportation, sludge removal, the big installation involving SO_2 equipment.

Notwithstanding those limitations and considering only the limitations of resources, the resources being engineering and construction manpower, to get this job done by 1983 would effectively require the doubling of the present engineering and construction staffs who are currently engaged in serving the industry, the industry being electric generating units.

We have a chart here entitled "Man-Years Required for Added Generating Capacity." The lower curve on this chart represents the number of people required for the normal business all through the years. The normal business being the installation of new units.

There is a little dip in the current year which is due mainly to the deferment and cancellations of nuclear orders. The curve is based upon our forecast of the growth in the industry to the year 2000 and the mix that is probable in the near term between fossil and nuclear.

We then estimated what manpower would be required, engineering manpower, to convert 90 percent of the existing oil and gas-fired utility units to burn coal. This would represent about 1,250 units that would be converted or substituted. We did not consider in this analysis the manpower that would be required to convert the currently listed 114 units that are able to be converted to burn coal, because they have burned coal before. Ninety-two of these have been ordered to convert.

We time phased for 1983 for installation the engineering manpower to convert 90 percent of the existing units. The peak that it adds to the normal load in the businesses is shown in red on that curve. You can see that it would require that we increase personnel in the industry by about 18,000 engineers each year.

Relate that to the number of engineering graduates that we have each year in this country. It is now running about 37,000. So, in addition to being able to recruit about 50 percent of all the 4-year engineering graduates in an industry that has never been able to recruit more than 10 percent in the past, you would in some magical way, have to recruit these men with the equivalent of a college education plus about 5 to 8 years of experience, which would be about the experience level that would be required to do this kind of work.

It would appear to us that this is quite an impossibility.

Of course, there is another thing that you could do. You could consider that, since we have grown at 10 percent in the past, we could continue to count on 10 percent in the future. In that way, by 1983, you could probably get some 15 percent of these units converted—replaced, really, more than converted.

Additionally, in this chart we have taken no account of the fact that the units that presently are thought to have coal burning capabilities would actually require some varying amount of engineering and construction to be put back to a condition to burn coal—a number that would be pretty hard to estimate because you would have to make a study to see what their current condition is.

In a similar manner, departing from the engineering, we then addressed ourselves to the construction problem. The lower curve, like the previous curve, shows the requirement for construction manpower for the presently contemplated normal growth and, again, the peaking on top of it, to get in the converted units, or replaced units, by a 1983 date. That just about covers the total existing work force.

The total number of people involved in the construction trades is actually somewhat in excess of this peak, of course, but utility construction would not only be the only work going on at this time.

There is another factor that we did not take into account. To get the job done in this period of time would require the outage on many units simultaneously, and the capacity of most of the electric utility systems could not tolerate that kind of a simultaneous outage and still serve the load.

End of my story, gentlemen.

The CHAIRMAN. Mr. Wheeler?

STATEMENT OF CLARENCE IKE, VICE PRESIDENT AND GENERAL MANAGER, FOSTER WHEELER ENERGY CORP.

Mr. IKE. Mr. Wheeler could not attend today, so I am attending in his place.

I am Clarence Ike, vice president and general manager of Foster Wheeler Energy Corp.

We have studied this from a little different point of view, in looking at the manufacturing capacity of the industry to do the conversions of these units.

The CHAIRMAN. Are you talking about replacement of old units?

Mr. IKE. Conversion and replacement, between now and 1983, if it is possible.

In the United States today, 36 percent of all the electric power generated by public and private utilities is generated by oil or gas-fired boilers. This amounts to 141,000 megawatts of installed capacity. Gas-fired utility boilers are incapable of being converted to coal firing with present technology; therefore, all of these units would have to be replaced in total.

Also, small oil-fired units of 50 megawatts and under could not practically be converted to coal. The total megawatts falling in the above two categories are approximately 26,000 megawatts.

These are oil-fired units which have been designed for peaking service. We would expect that a large number of these cannot be converted to coal firing. For the purposes of this study, we have conservatively assumed that 50 percent of these units would have to be replaced. Since there are 11,500 megawatts of peaking capacity, this would require a replacement of 5,750 megawatts.

Units which have been designed primarily for oil can, in general, be converted to coal-fired units with modifications both internal to the boiler and external consisting of the addition of coal pulverizing capability and modifications to the burners on the boiler. Obviously, outside the limits of the boiler itself, there are many additions required such as coal bunkers, coal-handling equipment, land for storage of coal ash disposal equipment and stack gas cleanup systems which are more extensive in their use of space and equipment.

We have disregarded the effect of furnishing this equipment in this study. Again, conservatively, we have assumed the conversion of an oil-fired boiler to a coal-fired boiler will reduce the capacity of the boiler by approximately 20 percent.

In some cases, this percentage will be much larger than this and in a few cases somewhat smaller. In this category of boilers, we have a total of 100,000 MW of capacity. The conversion of these units to coal will then require an additional 20,000 MW to be installed to make up for the loss due to conversion.

As a result of all of the above, it will be necessary to install 51,500 MW of new capacity to replace the capacity loss due to converting to coal and scrapping of units no longer being fired by gas. Between now and 1984, this new capacity will require the expenditure of 24,300,000 man-hours in the shops of the four major boiler companies supplying the electric utility industry.

In addition, the conversion of the 100,000 MW of oil-fired units plus an additional 10,000 MW of peaking units and miscellaneous other conversions will require 20,900,000 man-hours during this same period in these same shops.

We thus have a required expenditure of 45,200,000 man-hours between now and the end of 1983. These shops at the present time have work scheduled for this period. The remaining man-hour capacity left in the shops of the four boiler companies during the period between now and 1983 is 47,450,000 man-hours. The shops which we are speaking of are shops which specialize in the fabrication of key parts of a fossil fuel fired steam generator boiler. This type of facility is not available anywhere else in the United States.

In making this study, we have only considered the unique part of the equipment which the boiler industry fabricates. There are many other parts of these boilers which are, and can be, fabricated in other industrial fabricating facilities.

From the figures, I have mentioned, it can plainly be seen that in order to accomplish this conversion by 1983, it will be necessary to use the entire capacity of the industry between now and then. There would be no available manufacturing capacity for new installations of fossil fuel powerplants.

Based on a minimal load growth of the energy requirements, we have estimated that it will be necessary for the utility companies of the United States to purchase 10,000 MW of capacity in 1977, 15,000 MW in 1978 and 20,000 MW per year in 1979 through 1983.

This would translate into man-hour requirements in the boiler industry shops between now and 1983 of an additional 40 million man-hours.

So we have 47,000 man-hours available. It would require 40 million to convert. Where do we get 40 million for any new capacity? It is just not available.

We are a very capital-oriented business. It takes quite a while for us to expand our capacity and we would be talking about almost doubling the capacity. Once the conversion is done, what do we do with this capacity.

The CHAIRMAN. As I understand what you are saying, between the two witnesses, you do not have the engineers and you do not have the manufacturing capacity to accomplish utility conversion for the near future, is that correct?

Mr. IKE. That is correct.

Mr. SHERMAN. That is correct.

The CHAIRMAN. Assuming that you could accomplish the conversion goal you would have the problem of trying to gear back down and find something else for your people to do.

Mr. SHERMAN. In our case, we could not solve the first problem. You cannot get the people, they are not there. The engineering——

The CHAIRMAN. The Nation does not have enough engineers to do what is being called for.

That makes me ask, could you not spread one man's responsibility further so that one man could supervise a large number of people at work?

Mr. SHERMAN. Unfortunately, the job of conversion is more complicated, actually, than starting on a brandnew installation, because you are going into an existing plant and cutting in on it. You would get almost no two alike of those that you would be cutting in on. In addition to that, you would have to start the work by actually sending people out to the plant, because a plant that has been in existence for 10 or 15 years is actually not in the physical condition that the drawings you would be looking at show. There have been changes and alterations made and things moved around.

You would have to go out and determine the plant's current condition, record it, and then take this data back to wherever you were going to do the engineering work.

All these jobs would be more dissimilar than starting off to redesign and build brand new plants. So, the average level of man used on this conversion or additional work would be a higher level than you would normally use.

The CHAIRMAN. Well, if you were trying to solve this problem starting from scratch and someone came to you and said, "Here is what I want to do and here is what my problem is," what would your advice to him be? How would you suggest solving the problem?

Do you have any ideas? I would think you might offer some suggestions as to how he might go about ending his problems.

Mr. SHERMAN. Yes. The only way I could visualize doing that is to start off by converting or changing the largest, easiest units to change and work on them rapidly to get as many done as you can.

As I said, I think between now and 1983, if you did not have too much trouble with the environmental licensing, you could probably get some 15 percent of them done.

The CHAIRMAN. Senator Packwood?

Senator PACKWOOD. No questions.

Mr. IKE. If I may comment, I do not believe people realize how highly engineered these boilers are. Every single boiler that is put on in this country is a complete design. We do not reach out and pick them off the fence, we do not design the buildings and the equipment just by buying them like a car.

They are completely designed by engineers and then physically manufactured in our plants. They are put out piece by piece in the field.

The CHAIRMAN. Let me ask a question. Why can you not make a standard design and build a standard-type plant?

Mr. SHERMAN. Well, one of the reasons is that you do not have standard foundation conditions. Also, you do not have standard fuel and there is a big difference in burning. The burning of coal has different specifications, with ash contents of different characteristics as well as temperatures, and things like that.

You can build two duplicate units side by side at the same site, and they are duplicate units, that is true. If you were going into a powerplant that had two or three oil or gas-fired units and you were going to replace them with two or three coal-fired units, the boilers themselves would be the same.

Their configuration on the site and their connection to the rest of the plant, such as the turbine plant and everything else, that would be different. That would be individually engineered, but the boiler units themselves would be the same for that particular plant.

The CHAIRMAN. Thank you very much.

[The prepared statement of Mr. Sherman follows:]

STATEMENT OF R. J. SHERMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER EBASCO SERVICES INC.

SUMMARY

1. Physical space requirements may limit the ability to convert oil and gas fired units.

2. Conversion of existing oil and gas fired electric generating units in the United States by 1983 would require more than doubling of the engineering and construction labor staffs currently working on electric generating units.

3. To supply the engineering manpower necessary for conversion would require 50 percent of the total engineering graduates in the United States in the next two years. These graduates would not be adequately trained to perform this work until mid-1980's.

STATEMENT

Members of the Senate Finance Committee, Ladies and Gentlemen: I am R. J. Sherman, President and Chief Executive Officer of Ebasco Services Incorporated, with main offices located at Two Rector Street in New York City. Ebasco is a large engineering and construction company, primarily involved in the design and construction of electric generating plants for utility companies both in the United States and throughout the world. We have been in this business for more than 70 years and have been involved in the engineering and design and/or construction of a significant portion of the electric generating capacity in the United States. I have been with Ebasco for 39 years. I am a licensed professional engineer and served in Ebasco's engineering and construction departments prior to becoming an Officer of the company.

I want to present Ebasco's evaluation of the impact on engineering and construction manpower if any decision is to be made to convert all existing utility oil and gas fired steam-electric generating units to coal.

We recognize that there are many practical limitations involved in the conversion to coal of existing oil and gas fired steam generating units that currently exist in the electric utility industry, exclusive of those in the industrial sector. These limitations include: environmental and physical space requirements for replacement boilers, coal storage, ash storage and sludge disposal—assuming SO_2 removal scrubbers would be required on all units. We also recognize that limitations of boiler and other equipment manufacturing capacity would control overall length of time required for conversion to coal. Notwithstanding these limitations, conversion of all existing utility oil and gas fired electric generating units in the United States by 1983 would essentially require doubling of the engineering and construction labor staffs currently working on electric generating units.

The chart entitled, "Man years required for added generation capacity—engineering" shows on the lower dark curve Ebasco's forecast of the engineering manpower required to meet the planned new utility generating capacity to the year 1990. This curve is based on Ebasco's current forecast of the future peak loads and the nuclear and fossil capacity necessary to meet these loads. I might add that Ebasco's load forecast is quite close to the current forecast of the Edison Electric Institute. The substantial dip in forecasted engineering requirements in the next few years results from the recent major reduction in orders and deferments of nuclear units.

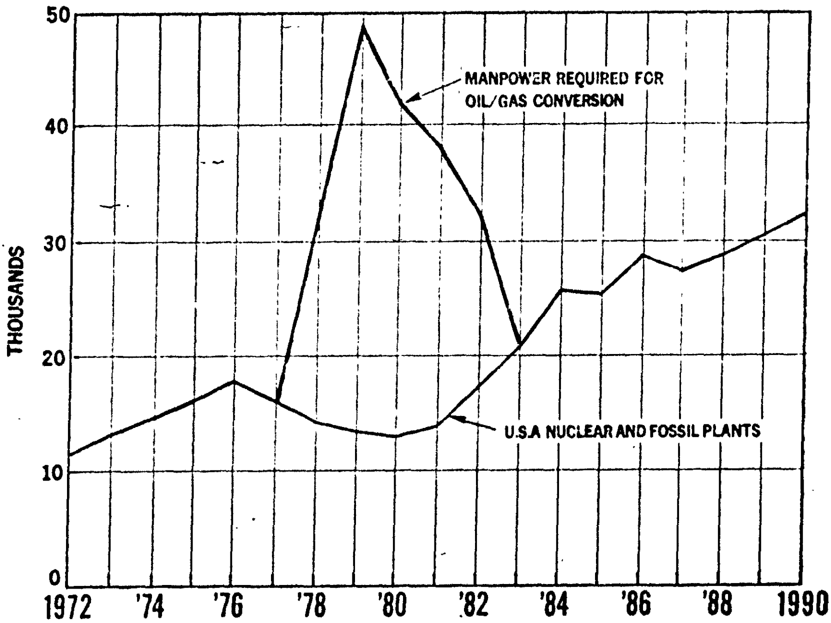
We then estimated the engineering manpower required to convert 90 percent of the existing oil and gas fired utility units to burn coal. In our analysis, we did not consider those oil and gas units currently listing coal as an alternative fuel, although there could be significant mandays involved in going into full generation with coal. The engineering mandays required to convert the existing units were then time-phased to support a 1983 installation date. The resultant peak is shown in red on the chart. As you can see, the conversion work would require more than double the existing engineers in our industry and the increase would be steeper than anything we have experienced in the past. To illustrate this sharp rise more clearly, we estimate that in 1978 and 1979, the industry would have to increase the number of engineers by approximately equal to the total number of Bachelor of Engineering Degrees granted throughout the country in 1976. The energy field generally receives about ten percent of those graduates. In addition, the engineers needed for this conversion work will have to be experienced, highly skilled individuals, who can adapt the new fuel cycle to the existing power plants. In my opinion, such a sharp increase in engineering manpower could not be supported by our industry.

In like manner, we analyzed the construction manpower requirements as are shown on the chart entitled, "Man years required for added generating capacity—construction." The lower or dark curve shows Ebasco's forecast for construction craft manpower for new U.S. nuclear and fossil plants. This forecast was developed in a manner similar to that described for engineering and agrees quite closely with an independent forecast developed by the Contractors Mutual Association. We superimposed in red on the base curve the additional construction craft manpower required to convert 90 percent of the existing utility oil and gas units. Again, we have indicated the need to more than double the existing workforce to handle this conversion work. Whereas the construction trades in total have memberships in excess of the peak forecast, it is questionable if the particular skills necessary for the conversion work could be developed in the short time available while meeting other requirements.

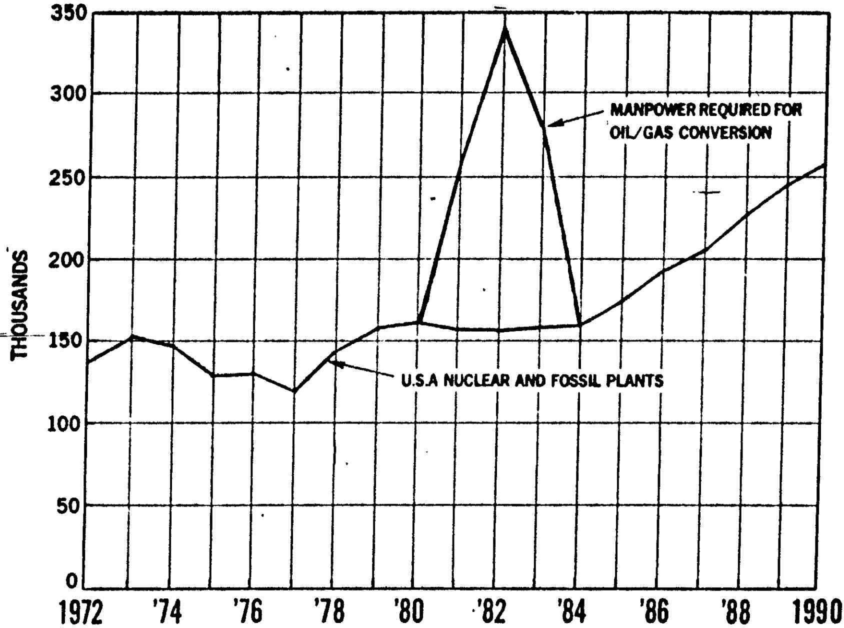
I would be happy to answer any questions relating to the charts of my testimony.

MAN YEARS REQUIRED FOR ADDED GENERATION CAPACITY

ENGINEERING



MAN YEARS REQUIRED FOR ADDED GENERATION CAPACITY CONSTRUCTION



The CHAIRMAN. We will stand in recess until 10 o'clock tomorrow.

[Thereupon, at 12:35 p.m., the hearing in the above-entitled matter was recessed, to reconvene at 10 a.m. Friday, August 12, 1977.]

ENERGY TAX ACT OF 1977

FRIDAY, AUGUST 12, 1977

U.S. SENATE,
COMMITTEE ON FINANCE,
Washington, D.C.

The committee met, pursuant to recess, at 10 a.m. in room 2221, Dirksen Senate Office Building, Hon. Russell B. Long (chairman of the committee) presiding.

Present: Senators Long, Matsunaga, Packwood, and Roth, Jr.

The CHAIRMAN. This hearing will come to order. The witnesses have 10 minutes to summarize their statements, at the conclusion of which each Senator will interrogate each witness for 10 minutes for the first round. If they want to ask further questions, thereafter, they may.

Our first witness this morning is Mr. George H. Lawrence, senior vice president, public affairs, American Gas Association.

Mr. Lawrence, we are very pleased to have you here before our committee this morning.

STATEMENT OF GEORGE H. LAWRENCE, PRESIDENT, AMERICAN GAS ASSOCIATION

Mr. LAWRENCE. Thank you, Mr. Chairman.

Mr. Chairman, I am George H. Lawrence, president of the American Gas Association. I would like to use some of my 10 minutes to summarize and address an overall theme that is of considerable concern to us and to many members of this committee.

I think that there have been numerous indications that the President's energy proposal places financial burdens on the consumer in the form of additional taxation, and not nearly enough emphasis on financial incentives directed toward developing new supplies of energy which we so urgently need.

I think in the case of the natural gas industry, that is most dramatically indicated because I think gas, to be quite blunt about it, in the early stages of the policy planning of this administration, was given very short shrift. Natural gas does not even enjoy, in many instances, the incentives that it would have reached under continued regulation.

We think this is not in the best interest of the consumer from many standpoints. We find this to be a paradox from the standpoint of the administration, which stresses resource efficiency. Natural gas is our most efficient form of energy, because it does not have to be transformed, and it is our cleanest form of energy. Since it does not pollute air, land or water. For these reasons, it will continue to be our most economic and environmentally acceptable form of energy.

For example, the administration's plan would allow natural gas production to decline rather dramatically to something like 16 trillion cubic feet a year by the year 1990. We submit that the removal of the Federal field price controls that have been imposed on us for 23 years would permit us to continue the present production level at almost 20 trillion cubic feet a year. That 4 trillion cubic feet of additional natural gas production would have to be made up by imported oil or other domestic energy sources, primarily domestically developed electricity.

I would like to review some of the economics of that in just a moment. I think one of the reasons that natural gas has been given short shrift is because we have a supply problem. Production has been in decline, but we think this is solvable. Because of that production decline, there is a tendency to say natural gas has no contribution to make in the long-term future, that we are running out and that is it. But this is not the case. The potential conventional supplies of natural gas by various estimates are in the range of 35 to 60 years at current rates of production.

When we consider supplemental supplies, such as coal gasification, liquefied natural gas, gasification of hydrocarbon products, et cetera, we submit there is substantial additional production available that could be in the range of 14 trillion cubic feet by the year 2000, or 14 quads of energy. Here, we have not even addressed the vast potential that might be available through research to unlock the tight formation seams of Appalachia or the Rocky Mountain area or the geopressured aquifiers in the gulf area where the potential supplies are estimated by some to be as great as our coal resources in the United States.

Today, we are devoting minimal research funds to those efforts. We submit that, given reasonable devolopment and production incentives, natural gas in the year 2000 could be contributing about the same 30 percent of the total energy mix that it is now contributing. Conventional natural gas supplies could be maintained at the current level of 20 trillion cubic feet a year; supplemental supplies at a level of about 14 trillion cubic feet a year.

If we were fortunate enough to obtain research breakthroughs in the new, more exotic areas, that contribution could even be greater.

Now, if this production level of contribution should slip by 10 quads of energy, for example—and the administration's plan would have it slipping by 10 quads of energy, not by the year 2000, but by the year 1990—then that slippage has to be made up by domestically produced electricity. The estimated cost of this is $275 billion.

Even considering our supplemental supplies of gas, Mr. Chairman, we submit that their cost would be in the range of $85 billion for the same amount of energy, since natural gas supplies cost substantially less.

So, we submit that the President's plan, which would raise the price of natural gas to industrial users by imposing an industrial use tax, is the wrong approach. This tax should be removed in its entirety. The House Ways and Means Committee took some substantial steps in that direction. I think they removed about two-thirds of its ultimate application, and we applaud their action, and we think the remaining one-third should also be removed.

There are also some technical points in the bill that should be corrected. We think there is some double taxation on synthetic natural gas feedstocks, such as naphtha and natural gas liquids, that should not be subjected to double taxation through the crude oil equalization tax and the industrial users tax. We also think perhaps it is truthfully time for the Congress to focus now on some positive energy tax incentives instead of the punitive approach of the industrial users tax.

We recommend a permanent investment tax credit of 12 percent instead of 10 percent removing the on-again/off-again nature of the investment credit that has existed over the years. In the case of our regulated companies, there are some instances where we have obtained regulatory permission for specific consumer surcharges devoted to certain specified exploration, development, and supply projects. But, the IRS has treated that surcharge revenue as gross income instead of permitting those revenues to be applied directly to the projects to which they were devoted on a dollar-for-dollar basis. Without relief from this IRS interpretation, this means you will have to charge the consumer twice as much to get the dollar actually to be applied to the project. We also think there are some instances where some of the start-up costs for supplemental supply projects by our regulated distribution and transmission companies, such as for exploration, development, engineering studies, environmental studies, impact studies, and so forth, should be expensed rather than capitalized.

We do not think that current IRS interpretations requiring capitalization of these items is consistent with encouraging these new energy projects to get underway. We also think it might be time to really consider some of the World War II-type emergency approaches creating a new tax classification for qualified energy property providing a depreciable life of 8 to 10 years with an increased investment credit of a 5-year amortization of the costs of the facility with no investment credit. This would be a direct encouragement toward getting these projects underway.

In summary, Mr. Chairman, we in the gas industry find a great deal wrong with the President's energy plan. It fails to provide the incentives necessary for the gas industry to continue its contribution to the long-term energy needs of this Nation. Thank you.

The CHAIRMAN. Thank you very much, Mr. Lawrence. You have provided us with a wealth of information, in addition to your prepared statement, and the reason I scheduled these hearings at this point was so that the Senators could study this material and material of this sort during the recess.

We are sending this information to the Senators as fast as it can be delivered to them, and the same will be true of your statement as well as any backup documents that you provide to us. I want to assure you that I am going to study them. We will have occasion to get benefits from this information when we hear from other witnesses from industry, such as the American Petroleum Institute when we come back in September.

I want you to know that I appreciate this very useful packet of information you provided us. I will see to it, insofar as it is in my power, that every member of the committee gives it the attention that it deserves and thoroughly studies it.

Thank you very much.

Senator PACKWOOD. I have no questions.

The CHAIRMAN. Thank you very much.

[The prepared statement and attachments of Mr. Lawrence follows. Oral testimony continues on p. 364.]

STATEMENT OF GEORGE H. LAWRENCE, PRESIDENT, AMERICAN GAS ASSOCIATION

SUMMARY

Even though natural gas production has declined in recent years, a continuation of this decline is not inevitable. The gas industry believes these projections are wrong. We are concerned that the Administration's proposed energy plan doesn't provide sufficient incentives to increase domestic energy supplies.

Such a pessimistic view is undesirable and not in the public interest. Natural gas is our cleanest and most efficient fuel. There are large recoverable supplies of natural gas as well as substantial supplemental supplies that could be produced from coal gasification, SNG and LNG.

Virtually every recent analysis of remaining recoverable resources of natural gas conclude there are between 700 and 1,200 Tcf of remaining conventional gas in the U.S. This represents a 35 to 60-year supply. In addition, we project a significant potential contribution from supplemental gas sources.

We are strongly opposed to the industrial use tax on natural gas. Even though it has been modified by the House Ways and Means Committee in H.R. 8444, we urge this Committee to delete this section of the bill. We support the phase out of burning gas for electrical generation and other major industrial boiler fuel uses in excess of 3 MMcf per day (essentially, the lower FPC priority use categories.) We also think conversion to coal should be encouraged where feasible with proper safeguards. But, we urge this be accomplished through established regulatory channels and through appropriate incentives rather than by punitive taxes.

We also urge this Committee to make two technical corrections in the bill concerning application of the crude oil equalization tax and the industrial use tax on feedstocks used in the production of synthetic natural gas. Naphtha and natural gas liquids used as feedstocks in the production of SNG should be specifically exempted from these taxes. This exemption would be in complete conformity with the legislative intent of H.R. 8444 since these feedstocks uses are not subject to either conservation or conversion.

Instead of imposing punitive tax measures to bring natural gas supply and demand into focus, A.G.A. recommends the following positive tax incentives to encourage exploration, development and production of both natural gas and other supplemental supply sources.

The investment tax credit should be increased from 10 to 12 percent on a permanent basis with normalization requirements unchanged. The investment credit limitation should also be removed to permit full use of the credit up to 100 percent of tax liability.

Any surcharge revenue collected from customers under appropriate regulatory safeguards to be used exclusively for the exploration for, and development and transportation of, new sources of natural gas should be excluded from the gross income of the gas company.

The costs of geological and geophysical work, feasibility and environmental studies, certification, start-up programs and other pre-operating expenses (including training costs) related to the establishment of new domestic energy facilities should be deductible as incurred, rather than capitalized and recovered over a period of years.

A new tax classification for energy property should be created providing at the taxpayer's binding election:

A depreciable life of 8–10 years for the qualified facility with an increased investment credit rate of 20 percent with normalization required, or

A five-year amortization of the cost of the energy facility, with no investment credit, but with normalization required. This would be comparable to the emergency facilities amortization concept used in World War II.

STATEMENT

I am George H. Lawrence, President of the American Gas Association. A.G.A. is a national industry association representing over 300 natural gas transmission and distribution companies. A.G.A. members serve over 160 million consumers and provide over 85 percent of the gas utility service in this country.

The energy crisis, which has faced and is continuing to face our country, whether measured in terms of a growing dependence on imported oil, or the actual shortage situations such as occurred this past winter, or on predicted future problems is to a large degree a manifestation of the growing natural gas shortage. There is general agreement that this gas shortage is the result of the counterproductive Federal laws, regulations and policies which have kept gas prices regulated well below the minimum level that would promote exploration for and development of new supplies. In addition, the artificially low price of gas has encouraged its expanded use and has often led to wasteful consumption.

Our major concern with the Administration's national energy plan is whether it can provide sufficient development of energy supplies to meet national energy requirements for the next 20–25 years.

Our reservations focus on the direction chosen for national consumption and production patterns for all domestic energy sources. Every shortfall in meeting the national energy objectives outlined in the President's plan will require a further increase in oil imports with the negative policy implications of increasing foreign source reliance and continuing deficits in our foreign balance of payments.

National energy shortfalls could be partially alleviated by maintaining U.S. production of natural gas at current levels of almost 20 Tcf per year, given the proper incentives—which U.S. producers have never had. Natural gas went from the post-World War II oil by-product stage directly into a stifling environment of field price controls in 1954. This led to a steady 16-year downward trend in exploration and development. It is an intolerable situation that there has not been at any time an effective exploration incentive for natural gas—our nation's cleanest and most efficient energy source.

To correct this problem, the gas industry urges Federal and legislative actions to achieve the goals detailed in the attached briefing package. Supplemental supply sources, the deregulation of new gas, and positive exploration, development and production tax incentives could play a major role in mitigating energy shortfalls and minimizing further increases in foreign oil imports. However, this possibility has evidently been rejected by the Administration, this possibility has evidently been rejected by the Administration through its heavy tax penalties on natural gas use, instead of through more constructive field price and tax incentives to ensure supply improvement.

FUEL MIX AND NATIONAL GOALS

The President's program calls for overall energy growth of roughly 2 percent a year from 1976's level of 74 quads, creating a demand for 92.8 quads by 1985. While 2 percent national energy growth rate is an admirable goal, it may be very difficult to achieve without potential reductions in economic growth. When fuel balances by sector are reviewed, 10.0 of the additional 18.8 quads of projected energy growth between 1976 and 1985 are for new electric generation. Of the remaining 8.8 quads of energy growth, 6.2 quads will have to be provided from direct use of coal in industry. Nuclear capacity will have to increase 400 percent between 1976–1985, and national coal production will have to double by 1985 (See Attachment 1). Prudent national policy should provide incentives for domestic supply growth of natural gas in the event either demand exceeds supply or the large additional supplies from coal cannot be developed for supply or environmental reasons.

The Administration's plan may create a serious energy supply problem by setting ambitious goals for coal, nuclear and electrical power while inhibiting natural gas development which can only result in increasing reliance on foreign oil imports. Instead, it should be concentrating on ensuring a readily available supply of natural gas, to enable our nation to meet the national energy goals of reducing oil imports from a potential level of 16 million barrels a day to less than 6 million barrels.

The national energy goals call for an increase in coal production by more than 400 million tons by 1985. This objective appears optimistic based on the fact that the coal industry has developed only 20-25 major new coal mines in the past twelve years, not to mention transportation, mining restrictions, and the environmental considerations. The nuclear power objectives of the plan may also be optimistic when the recent history of development in this industry is taken into account.

All of these factors seem to indicate that the Administration's plan is overly optimistic on the low side with respect to demand growth and on the high side with respect to production of coal and electrical power. The plan is also unduly pessimistic concerning the potential contribution of natural gas. If natural gas and supplemental gas supplies are not developed to their full potential, additional shortfalls will have to be made up from imported oil.

NATURAL GAS SUPPLY CONSUMPTION

The President's program seriously inhibits the development of new natural gas supplies. It will result in a significantly lower contribution from conventional and supplemental gas sources than with deregulation of new gas prices and a favorable government climate towards supplemental natural gas sources. Under a ceiling price for new gas (lower than even the new oil ceiling price), lower 48 state production is projected by the Administration to continue its decline, dropping to 17 Tcf by 1985 and 16 Tcf by the early 1990's.

Our recent analysis of the impact of the proposed $1.75/Mcf new gas price ceiling on domestic gas production indicates that the proposed new gas ceiling price will result in even lower production than expected by the Administration. (See Attachment 2). The onshore supply impact of the President's proposed new gas ceiling price through the mid-1980's is expected to be a 0.1 to 0.3 Tcf reduction in annual production below levels expected under existing FPC regulation through Opinion 770A. Offshore, the Carter plan is expected to result in no significant change in production levels expected under continued regulation until the mid-1980's, primarily because offshore gas development involves long lead-times. Also, liquefied gas imports, synthetic natural gas and coal gas are not expected, nor permitted, to make significant contributions to supply.

Beyond 1985, the net effect of the President's new gas pricing proposal compared with continued regulation is expected to be a 0.2 Tcf increase in total U.S. gas production in 1985, rising to 0.6 Tcf annually in 1990. But, when compared with higher annual gas production expected under deregulation of new gas prices, the Carter plan is expected to result in 0.4 less production in 1978, 1.6 Tcf less in 1980, 3.7 Tcf less in 1985, and 4.8 Tcf less in 1990.

As shown in attachment 3, the gas industry could provide roughly 6.6 quads of additional energy by 1985 with deregulation above the 18.8 quads projected in the President's program. As mentioned, residential and commercial gas consumption increases are projected to average only 0.6 percent between 1976 and 1985. (The residential sector would grow 1.9 percent annually while the commercial sector would decline 1.2 percent annually). But, by 1990, the residential and commercial sectors are projected to consume almost 50 percent more natural gas than in 1985 (reaching an annual growth rate in this period of 8.3 percent).

Those who suggest that a decline in the contribution of gas is inevitable should recognize:

Proven reserves and potential gas resources, coupled with economically feasible supplemental gas supplies and a strong conservation ethic, are adequate to meet not only existing gas demands but even increased demand well into the next century.

The potential for technological breakthrough with respect to gas energy is great and if it occurs would provide an almost unlimited supply of usable energy for most purposes.

COST OF ADDITIONAL ELECTRIC INVESTMENT VS. GAS

National electrification will prove extremely expensive for the American public and the nation. Based solely on requirements for gas and electricity, as indicated in the national energy plan, the nation will need by 1985 to produce for end-use an additional 3.1 quads of electricity. The annual incremental consumer cost (in 1976 dollars) for an additional 3.1 quads of electric energy by 1985 would total approximately $43 billion versus roughly $17 billion, if additional natural gas from deregulation and supplemental gas from LNG and coal gasification were used instead of this electricity (See Attachment 4). Further, the capital costs for this amount of electricity would be about $150 billion; whereas for natural gas, it would be less than $20 billion.

Preliminary analysis, in Attachment 4, covering national costs of an additional 3.1 quads of electrical energy indicates substantial savings to the nation if natural gas and supplemental gas supply sources were used as a substitute for the additional electric consumption. These residential consumers will pay nearly $11.2 billion more annually if our nation chooses to emphasize electricity rather than natural gas. For these industrial customers, $15.6 billion annually would be saved by substituting natural gas for proposed additional electricity.

We are not herein deprecating the increased need for coal and nuclear-generated electricity. Indeed, if we are going to meet even the very modest energy growth rates through the year 2000, we will need to develop all our domestic energy sources to the maximum extent. But, again we cannot reconcile the Administration's plan with its complete lack of incentives for both natural and supplemental gas supplies when alternate forms of energy are both more expensive to the consumer and less environmentally acceptable.

The proposed increase in electrical consumption which the President's plan fosters would prove costly. Natural gas can play a far greater role than the Administrator envisions. Gas now provides about 30 percent of the nation's total energy mix and with reasonable development incentives and research efforts it can continue to supply that portion of our national energy mix into the year 2000.

I urge this Committee to keep this potential for the natural gas industry in mind, as I review specific energy tax provisions of H.R. 8444 and S. 1472.

INDUSTRIAL USERS TAX AS PROPOSED BY THE ADMINISTRATION (S. 1472)

We are vigorously opposed to the industrial users tax on natural gas. Based on projected fuel prices and available coal conversion cost data, the Administration's proposed industrial users tax on natural gas would provide almost no incentive to convert the majority of gas-using equipment to alternate fuels. In 1976, almost 80 percent of industrial gas use, or about 5.6 Tcf, was for process, feedstock, direct-fired and small boiler applications. The average cost of converting these gas uses to alternate fuels is estimated to be $40 per annual MMBtu consumed, with a range from $6 to $500 per MMBtu. These gas uses would not be economical to convert to alternate fuels, yet would still be taxed under the Administration's proposal in S. 1472. The tax would not lead to any significant conversion of these uses before 1985, yet will cost industry, and eventually the ultimate consumer, $40 billion (See Attachment 5). This tax only generates a revenue windfall to the U.S. Treasury instead of providing positive tax incentives to energy suppliers.

The other 20 percent of industrial gas consumption (approximately 1.4 Tcf) is used in large industrial boilers that are generally less expensive to convert. However, regardless of the Administration's proposed tax on natural gas use, about half of this gas usage is expected to be converted to alternate fuels by 1985 anyway. This would be a direct result of curtailments since industries will not have enough gas under the President's price ceiling proposals.

Thus, the maximum conversion from gas to other fuels that the Administration's gas users tax could stimulate in industry is somewhat less than 0.7 Tcf of the gas used in large boilers, since environmental and other restrictions will preclude achievement of full conversion. Yet, this minimal conversion would impose major economic costs to the nation.

As mentioned, the users tax would cost U.S. industries, and eventually the ultimate consumer, $40 billion in direct tax payments through 1985.

The average increase in industrial gas prices by 1985 with the tax is $1.40/Mcf over projected industrial prices of gas without the tax. The tax will greatly diminish regional differences in natural gas prices to industry, with a more substantial impact in the present lower-cost regions near producing areas. This is because the tax is tied to the price of distillate oil which does not vary greatly from region to region. For example, the tax will be large in the southern U.S. where gas prices are relatively low. But, the tax will have little impact in New England, where gas is currently higher priced because of transmission costs.

The estimated increase in the national annual inflation rate attributable to the Administration's proposed tax is about 0.3 percent with a range of 0.1 to 0.4 percent in the period from 1979 through 1984.

The rebates proposed in connection with the Administration's gas users tax are only intended to offset coal conversion expenses. Therefore, most of the estimated $40 billion direct cost to U.S. industrial gas users will be experienced as tax, the remainder as coal conversion expenses induced by the tax.

The tax operating in conjunction with the incremental pricing provisions and the coal conversion sections of the Administration proposal will have a detrimental impact on the capital formation capabilities of American industry. Conversion will create investment problems with dangerous economic side effects. Industry could be forced to make significant investments diverting limited capital resources into coal generation equipment, conservation devices and anti-pollution equipment, which shifts these limited capital resources away from more productive investments that would increase plant capacity, promote industrial growth and create new, additional jobs in the American economy.

INDUSTRIAL USERS TAX AS MODIFIED BY THE HOUSE (H.R. 8444)

The industrial users tax on natural gas has been substantially modified by the House. The limitations imposed reflect a constructive attempt by the House Ways and Means Committee to reduce the burdens and inequities imposed by the tax while retaining some of the more effective portions of the Administration's proposal. A.G.A. supports the efforts of the Ways and Means Committee, but urges this Committee to move further and delete this tax entirely from the bill.

We support the phase out of burning gas for electrical generation and other major industrial boiler fuel uses in excess of 3 MMcf a day (essentially, the lower FPC priority use categories). Also, we think conversion to coal should be encouraged where feasible with proper safeguards reflecting necessary lead time, availability of fuel, economic justifications and environmental considerations. But, while we favor a phase out of boiler fuel uses as I have outlined, we urge that this be accomplished through established regulatory channels and through appropriate incentives rather than punitive taxes.

Under the version approved by the House, the tax would now apply to three categories of natural gas use: electric generation, industrial boilers, and certain other non-exempt industrial processes. A smaller quantity of gas is now affected by the revised tax—about 3 Tcf instead of up to 7.1 Tcf under the Administration's proposal in S. 1472. The direct cost of the revised gas users tax to U.S. industries is estimated to be less than $14 billion cumulatively by 1985, compared with the estimated $40 billion direct cost of the President's proposed version of the tax (See Attachment 6).

However, A.G.A. stresses the administrative and regulatory burdens imposed by the House-passed version of the use tax on natural gas will prove complicated and burdensome for industrial users attempting to comply with the provisions of the tax. We urge this Committee instead to delete the industrial users tax on natural gas to avoid subjecting American industry to a blizzard of reports, regulations and statutory requirements.

Further, the industrial users tax on natural gas must also be viewed in light of the incremental pricing provisions adopted by the House in their action on this bill. The cost allocation of more expensive new gas and certain supplemental supplies to industrial users only, through the incremental pricing provision in H.R. 8444, sets a detrimental federal standard for the gas industry. We oppose any attempt to federally mandate this approach to industrial users only. Instead, we recommend this issue be left to the determination of State Public Utility Commissions in their ratemaking proceedings on gas utility rate filings.

We strongly urge the Senate to scrutinize this issue closely. Most arguments favoring incremental pricing are based on a modification of the classic economic theory of marginal cost pricing with incremental costs being charged to arbitrarily chosen classes of users—in this instance, the industrial users. But, we stress this approach is not applicable to the current situation in the gas industry since, almost without exception, the supplemental gas is not incremental. Instead, it represents the substitution for eventually declining traditional gas supplies, and it enables the industry to provide service to existing customers at traditional levels.

Incremental pricing will also have an inflationary impact on the cost of goods and services produced by industry, hiding from ultimate consumers the impact of energy price increases. Eventually, high priority residential and commercial users will pay higher prices for service as the high fixed costs of the gas system are spread over lower volumes of gas due to lower industrial load factors. Also, increased needs for storage capacity to supply the peak needs of increased residential and commercial use would exert an upward pressure on ultimate prices to the consumer. Indeed, the residential consumer of natural gas would, until the incremental ceiling price for low priority customers was reached, pay for natural gas at current rates plus inflation. This approach seems at considerable variance with the very ethic of the President's plan for having the American consumer pay the real price for energy to encourage conservation.

FEEDSTOCKS USED IN THE PRODUCTION OF SYNTHETIC NATURAL GAS

There are also two other issues concerning H.R. 8444 in the nature of technical corrections that we also urge this Committee to consider. A.G.A. is concerned with an apparent omission in Sections 2031 and 2041 of H.R. 8444 and corresponding explanations in the Ways and Means Committee report concerning use of naphtha and natural gas liquids as feedstocks. Our concern is with maintaining a favorable economic climate for production of synthetic natural gas (SNG), a viable near-term source of supplemental gas supply, which is produced mainly from natural gas liquids (NGL) and naphtha feedstocks. It is important to note here that naphtha is obtained during the refining of crude oil and does not fall within the definition of natural gas liquids.

As you may know, during the past cold weather crisis, SNG provided an extremely critical source of gaseous energy. Imposing taxes on SNG plant feedstocks through the crude oil equalization tax (Section 2031) and the industrial users tax (Section 2041) will raise the cost of SNG to gas consumers. For instance, preliminary estimates provided by one of our member companies indicate the crude oil equalization tax will raise the price of naphtha by four to seven cents a gallon, which will ultimately increase the price of SNG in the range of $0.40 to $0.70 per Mcf.

Such taxes would not result in conversion from SNG nor conservation of SNG to any significant extent. (The cost of SNG is already expensive compared with natural gas—$4.00–$5.00 per Mcf vs. $1.00–$2.00 per Mcf.) The additional costs caused by these taxes would unjustifiably increase prices to gas consumers without accomplishing the Administration's goals of conservation or conversion.

A.G.A. urges this Committee to clarify these issues by amending the bill to specifically exempt naphtha and natural gas liquids used as feedstocks in the production of SNG from the crude oil equalization tax and the industrail users tax. This exemption would be in complete conformity with the legislative intent of both sections of the bill and would provide equitable relief for gas consumers using this vital supplemental supply source.

EXPLORATION, DEVELOPMENT AND SUPPLY TAX INCENTIVES

A.G.A. urges this Committee to consider the benefits of providing urgently needed exploration, development and supply tax incentives, rather than imposing punitive tax measures to bring natural gas supply and demand into focus.

INTANGIBLE DRILLING COSTS

A.G.A. supports the Administration proposal to limti the application of the minimum tax on oil and gas intangible drilling expenses to only those individuals sheltering other income through oil and gas leases. This would exempt from the minimum tax the many independent oil and gas drillers whose investments can provide significant contributions to increasing supplies of these valuable energy resources. Never has it been more critical that these independent drillers have the cash flow improvement offered by this tax relief.

The Congress provided relief in the Tax Reduction and Simplification Act of 1977 for only one year. However, this action must be extended for all years and made permanent to permit necessary long-range planning by these many independent oil and gas drillers.

INVESTMENT TAX CREDIT

A.G.A. recommends that the investment tax credit should be increased from 10 to 12 percent on a permanent basis with normalization requirements unchanged. The investment credit limitation should be removed to permit full use of the credit up to 100 percent of tax liability.

When I last appeared before the Committee on March 9, 1977, I strongly supported the Administration proposal to increase the investment tax credit from 10 to 12 percent on a permanent basis. The additional supply obstacles posed by the President's energy plan create an added sense of urgency for this investment incentive. The capital intensive nature of the gas industry dictates that we must engage in a massive captial program during the next two years. We anticipate capital expenditure requirements of $66 billion (in terms of 1975 constant dollars) by the mid-1980's. Also, if the industry faces decreased loads in the industrial and utility markets, this will place increased demands on the gas industry to develop additional storage capabilities at increased costs to the industry and ultimately to the consumer.

For the investment credit to achieve maximum effect, it must be made a permanent part of our tax laws like the depreciation deduction. Only a permanent credit will provide the stability and assurance necessary for the gas industry and financial community to plan and carry out supply projects necessary to meet national energy objectives.

Also, most importantly, to permit maximum use of the investment credit within the gas industry, the investment credit limitation msut be increased to permit full use of the credit up to 100 percent of tax libility. Under current low for purposes of this higher limitation, the term "public utilities" doesn't include utilities engaged in pipeline transportation of gas nor those engaged in developing supplemental gas supply sources, such as synthetic natural gas and liquefied natural gas. These excluded portions of the gas industry are the very segments that must raise the greatest amounts of capital in the near future. They also hold the potential to make significant contributions to increased supplies of our nation's premium fuel.

EXPLORATION, DEVELOPMENT AND ENERGY FACILITIES

As a further incentive for increased supplies of natural gas, A.G.A. also recommends that:

Any surcharge revenue collected from customers under appropriate regulatory safeguards to be used exclusively for the exploration for, and development and transportation of, new sources of natural gas should be excluded from gross income of the gas company, and also,

The costs of geological and geophysical work, feasibilty and environmental studies, certification, start-up programs and other pre-operating expenses (including training costs) related to the establishment of new domestic energy facilities should be deductible as incurred, rather than capitalized and recovered over a period of years.

Under current law, the term "gross" income under Section 61 generally means all income from whatever source derived. The IRS takes the position that any surcharge revenue collected for the sole purpose of exploration and development is included in gross income. The IRS has also challenged the deductibility of the costs of geological and geophysical work, feasibility and environmental studies, certification, start-up programs and other pre-operating expenses relating to the establishmnt of new domestic energy facilities. Instead of permitting a deduction for these expenses, the IRS is forcing companies to capitalize these expenses.

In an era of supply shortfalls and increased curtailments of natural gas, there is a need for a national emphasis on further exploration for and development of new supply sources. Drilling for natural gas is expensive and can run up to $350 a drilled foot. The costs of laying a mile of pipeline to reach the wellhead can run up to $700,000 a mile. The gas industry needs additional financial incentives to meet the high costs of further exploration and development. Many gas transmission and distribution companies are entering into exploration and development activities at great risk and expense to assure adequate supplies to meet their growing customer needs. Surcharges on gas customers' bills with appropriate regulatory safeguards would create additional capital for exploration and development of new natural gas supplies. But, inclusion of this surcharge revenue in the company's gross income diminishes its ability to form the necessary capital, and is counter-productive to long-range national energy goals.

If the federal income tax is applied to this revenue, the amount which is collected to pay the costs of exploration and development is, in effect, reduced by the percentage of the applicable corporate income tax rate, without any additional funding to make up this shortfall. Significant exploration and development by gas transmission and distribution companies is possible only if the necessary funds from such surcharges are excluded from the company's gross income. Any profits realized from such exploration and development ventures would be flowed back to the gas consumer.

New domestic energy facilities are also essential to meet our nation's critical natural gas supply requirements. Liquefied natural gas plants and coal gasification plants can make valuable contributions to meeting supply shortfalls, but they are very capital-intensive projects. Gas companies are currently experiencing severe difficulties in raising capital in conventional money markets. Deductibility as current expenses of the costs associated with the establishment of these new domestic energy facilities would enable the companies to generate the money internally for financing more of the actual construction of these projects. Forced capitalization of these expenses by IRS delays the generation of internal capital and inhibits the ability to finance further construction on essential production projects.

NEW TAX CLASSIFICATION FOR ENERGY PROPERTY

Finally, A.G.A. recommends that a new classification for qualified energy property (that is, property used in the search for or development and subsequent operation of new energy sources—such as coal gasification and other SNG plants and new pipelines) be created. This new classification would provide at the taxpayer's binding election:

A depreciable life of 8–10 years for the qualified facility with an increased investment credit rate of 20% with normalization required, or

A five-year amortization of the cost of the energy facility, with no investment credit, but with normalization required. This would be comparable to the emergency facilities amortization concept used in World War II.

This would provide the maximum opportunity to generate internally part of the financing necessary for the construction of new domestic energy facilities. It also would provide greater potential for supplemental gas production capabilities reaching 2.5 Tcf by 1980, and 5.5 Tcf by 1985.

I want to thank the Committee for the opportunity to testify today, and I will be pleased to answer any questions.

PROJECTED FUEL BALANCES BY SECTOR (ADMINISTRATION ESTIMATES)

[Quads—10^{15} Btu]

	1976 estimated	1985	1990
Demand	74.0	92.8	96.1
Residential and commercial:			
Oil	7.0	5.4	5.8
Natural gas	7.8	8.2	12.2
Electricity	[1] (3.9) 12.6	[1] (5.2) 16.8	[1] (5.2) 17.0
Coal	.2	0	0
Total	27.6	30.4	35.0
Industrial:			
Oil	6.4	8.0	11.4
Natural gas	8.8	9.0	6.3
Electricity	[1] (2.6) 8.4	[1] (4.4) 14.2	[1] (4.9) 15.6
Coal	3.8	10.0	4.9
Total	27.4	41.2	38.2
Transportation:			
Oil	18.4	20.4	21.0
Natural gas	.6	.6	.4
Total	19.0	21.0	21.4
Electricity:			
Oil	3.2	2.6	2.5
Natural gas	3.0	1.0	
Coal	9.8	16.6	17.2
Nuclear	2.0	7.6	9.3
Other	3.0	3.2	3.6
Total	21.0	31.0	32.6

[1] Energy required to produce electricity; amount in parentheses represents electricity distributed.

Impact of the President's Proposed \$1.75/MCF New Gas Price Ceiling on Domestic Gas Production

A. Introduction

A key element of the President's recently proposed National Energy Plan involves a national ceiling price for new natural gas in order to stimulate increased domestic gas production. The President's proposal would limit the wellhead price of new gas to the average cost of domestic crude oil acquired by refineries. This ceiling price is estimated to be approximately \$1.75 per Mcf at the beginning of 1978, and is projected to increase by about 7.5 percent per year thereafter. New gas produced and used within states (intrastate gas) would be subject to the same ceiling price limitation as interstate gas.

The purpose of this analysis is to evaluate the President's proposed pricing policy for new domestic gas in terms of its effects upon onshore and offshore gas production through 1990.

B. Executive Summary of the Results of the Analysis

The major conclusions of this analysis are as follows:

The onshore supply impact of the President's proposed new gas ceiling price through the mid-1980's is expected to be a 0.1 to 0.3 Tcf (Trillion cubic feet) reduction in annual production below levels expected under the existing FPC regulation (Opinion 770A).

This is because prices for new gas under the proposed ceiling are well below projected "free market" intrastate prices until nearly 1990, resulting in an immediate decline in projected onshore supply production.

For the first quarter of 1977, FPC reports that 64 percent of new contracts and 63 percent of renegotiated contracts in the intrastate market exceeded \$1.75/Mcf.

Offshore, the Carter plan is expected to result in no significant change in production levels expected under continued regulation (FPC Opinion 770A) until the mid-1980's, primarily because offshore gas development involves long lead-times.

Production of old interstate gas (pre-1973 vintage) under leases which expire after April 20th is not expected to significantly increase above currently expected levels in response to the maximum \$1.45 ceiling contained in the Carter Proposal.

Beyond 1985, the net effect of the President's new gas pricing proposal compared with continued regulation is expected to be a 0.2 Tcf increase in total U.S. gas production in 1985, rising to 0.6 Tcf annually in 1990.

Onshore production would return to currently projected levels under Opinion 770A as prices once more approach those which would have occurred in the intrastate market.

Offshore, as prices are allowed to rise above levels anticipated under present FPC regulation, production would climb above presently expected levels under 770A.

Compared with higher annual gas production expected under deregulation of new gas prices, the Carter plan is expected to result in 0.4 Tcf less production next year (1978), 1.6 Tcf less in 1980, 3.7 Tcf less in 1985, and 4.8 Tcf in 1990.

Impacts on Future Gas Supplies

The analysis of the President's new gas pricing plan is based upon evaluation of the supply response from the new gas ceiling price as escalated compared with prices under continued regulation and under deregulation. Under present conditions, most future supplies of new gas from onshore regions are responding to unregulated intrastate prices. Future offshore new gas supplies alone are presently responding to FPC regulated price ceilings.

President Carter's plan for pricing new natural gas embodies the following elements, summarized in Table 1:

The ceiling for new gas will be the same regardless of the market, interstate or intrastate, in which the gas is sold.

In the first quarter of 1978, the ceiling price will be \$1.75 per Mcf (see Table 1). From 1979 onward, the ceiling price for new natural gas will be equal, in cost per Btu, with the refinery acquisition cost of the average of all domestic crude oil. This price will be calculated quarterly based on the previous quarter's data.

The price of domestic crude will consist of the old oil tiers (including all oil first sold through 12/31/76) priced as under current regulations, plus new oil, the price of which will be allowed to rise in installments until in 1980 it reaches a level equal to the 1977 world oil price plus domestic price inflation from 1977 to 1980.

Knowledge of intrastate gas prices is sery imperfect. Up through 1971 they had been comparable to FPC ceilings, but after 1971 intrastate prices rose substantially above interstate prices. Partial data on new intrastate contracts by jurisdictional companies involved in non-jurisdictional sales) has been collected and published by the FPC for the 24 months from 1975 through 1976 (see Table 2). This data suggests the hypothesis that intrastate prices for new and renegotiated contracts are approximately equal.

TABLE 1.—1ST QUARTER 1978 "NEW" GAS PRICE—BASED ON 4TH QUARTER 1977-AVERAGE REFINER ACQUISITION COST[1]

Category[2]	MMB/D	Price per barrel
Lower tier	3.7	$5.52
Upper tier	2.9	12.38
Stripper	1.1	14.84
"New" oil	.2	14.84
Average all wellhead	7.9	9.56
Transportation		.60
Total cost		10.16
Natural gas conversion:		
Price per barrel		10.16
Mcf's per barrel	5.8	
Total		1.75

[1] FEA projections of controlled crude prices based on initial relaxation of current domestic crude price freeze in July 1977.
[2] Under the President's plan these categories will be redefined: Lower tier becomes tier I, upper tier becomes tier II and "new" oil becomes tier III.

TABLE 2.—RECENT INTRASTATE WELLHEAD GAS PRICES

[Dollars per mcf]

	New contracts			Renegotiated or amended contracts		
	High	Weighted average	Low	High	Weighted average	Low
1975 average	2.07	1.29	0.43	2.13	1.42	0.21
January	2.00	1.12	.49	2.17	1.44	.26
February	1.95	1.20	.43	2.07	1.49	.7
March	2.07	1.04	.56	2.08	.76	.25
April	2.04	1.54	.20	1.91	1.67	.25
May	2.04	1.42	.44	2.08	1.46	.19
June	2.12	1.20	.47	2.32	1.58	.20
July	2.08	1.48	.31	2.35	1.52	.26
August	2.20	1.36	.30	2.17	1.06	.44
September	2.14	1.42	.40	2.12	3.53	.25
October	2.03	1.05	.38	2.11	1.51	.13
November	1.94	1.36	.46	2.04	1.74	.37
December	2.16	1.34	.75	2.09	1.32	.38
1976 average	2.08	1.61	.49	2.19	1.64	.49
January	2.00	1.55	.14	2.21	1.84	.25
February	2.13	1.62	.15	2.21	1.70	.26
March	1.90	1.52	.71	2.21	1.62	.45
April	2.16	1.73	.51	2.09	1.22	.18
May	2.01	1.39	.15	2.34	1.83	.16
June	2.04	1.67	.29	2.18	1.71	.49
July	2.17	1.27	.49	2.21	1.15	.20
August	2.03	1.55	.40	2.29	1.69	.80
September	1.97	1.72	.93	2.28	1.95	.97
October	2.12	1.79	.47	2.16	1.58	.46
November	2.09	1.65	1.16	1.99	1.63	.54
December	2.33	1.85	.46	2.17	1.76	1.18

Source: FPC, Bureau of Natural Gas, "Intrastate Natural Gas Prices of FPC Jurisdictional Natural Gas Companies Selling More Than One Million Mcf Per Year in Interstate Commerce," FPC Form 45, 1975–76.

For the purpose of this analysis, estimated future intrastate gas prices are projected by calculating residual oil prices from OPEC crude oil escalated by matching consuming-nation's inflation rates (assumed to be 5 percent/year).

Existing FPC new gas price ceilings are quite definite. The FPC biennial review to establish new ceilings for 1977–1978 vintage gas is currently underway. There is considerable uncertainty regarding the prospective results of this, and future, biennial reviews. However, for the purposes of this analysis continued Opinion No. 770A escalations of 4¢/Mcf annually with no change due to biennial review was assumed.

Quantitative price projections for new gas are shown in Table 3 for each of the three cases analyzed: Continued regulating under 770A, the President's new gas ceiling, and deregulation.

Comparison of these prices reveals:

In the near-term, the proposed new gas ceiling prices are roughly in line with existing or anticipated FPC ceilings for interstate gas prices.

In the near-term the ceiling prices are however, well below anticipated intrastate prices.

Beyond 1985, the proposed new gas ceiling prices are above anticipated FPC interstate gas price ceilings. Given the long lead-times which characterize development of offshore resources, guarantees of favorable future prices—enacted now—can effectively set in motion the preliminary steps which will bring forth additional offshore gas supplies when the favorable prices come into effect.

Only beyond 1985 do President Carter's proposed new gas prices begin to approach levels presently anticipated in the intrastate market. Supplies from onshore, which generally can be developed more quickly than offshore may then be expected to begin to return to otherwise projected levels.

TABLE 3.—PROJECTED WELLHEAD PRICES FOR NEW GAS

[In current dollars per thousand cubic feet]

	1976 (estimate)	1978	1980	1985	1990
770A:					
Intrastate	1.64	2.25	2.80	3.75	4.79
Interstate	1.42	1.50	1 58	1.78	1.98
President's ceiling:					
Intrastate		1.75	2.09	3.24	4.27
Interstate		1.75	2.09	3.24	4.27
New gas deregulation [2]		2.80–4.44	3.49–3.84	4.80	5.37

[1] Inflation was assumed for all price increases (except for those under 770A.)

[2] Initial new gas prices under immediate deregulation of new gas are uncertain but are expected to rise to Btu equivalent of No. 2 oil refined from foreign crude by 1985. Range shown for early years reflects 2 initial gas price scenarios: $2.75 and $3.25. The $3.25 case represents the maximum price to which new gas could rise since it equals the most recent supplemental gas prices (e.g., LNG.)

TABLE 4.—SUPPLY IMPACT OF PRESIDENT'S PROPOSED CEILING PRICE ON LOWER 48 STATES NATURAL GAS PRODUCTION

[In trillion cubic feet]

	Estimated annual production			
	1978	1980	1985	1990
Offshore:				
FPC 770A	4.1	4.4	5.0	5.2
President's proposal	4.1	4.4	5.4	5.8
New gas deregulation	4.1	4.6	5.7	6.0
Onshore:				
FPC 770A	14.7	13.7	11.1	9.4
President's proposal	14.6	13.4	10.9	9.4
New gas deregulation	15.3	15.0	14.3	14.1
Total U.S. supply:				
FPC 770A	18.8	18.1	16.1	14.6
President's proposal	18.7	17.8	16.3	15.2
New gas deregulation	19.4	19.6	20.0	20.1

Estimates of potential future gas supplies, and their sensitivity to alternate prices, have been calculated with the aid of TERA[1] and of other computerized

[1] TERA: Total Energy Resource Analysis model.

gas supply simulation models. As a result of these supply sensitivity tests, the projections in Table 4 have been prepared as reasonable estimates of future gas supplies which may be forthcoming under existing conditions, and which might result from adoption of President Carter's new gas pricing plan.

The projections are based upon analysis of the effects of future prices on factors such as drilling, discoveries, reserve additions, and production. The time lags between each stage of the overall gas supply process, and the impact of Carter's Plan on near-term and mid-term gas production incentives, have been taken into consideration. Total gas supplies have been separated into interstate and intrastate markets, into onshore and offshore sectors, and into old gas and new gas vintages. Separate analyses have been performed of each aspect of President Carter's plan in these individual components, and the net overall impact assessed.

By 1990, President Carter's new gas pricing plan slightly accelerates the rate of overall gas production; but at the expense of considerable near-term reduction in annual supply. Onshore reserve additions will immediately be affected by the loss of 1.2 Tcf, though they will begin to return to normal by 1980 as new drilling patterns emerge. Offshore reserve additions rise by 1980 in anticipation of production levels in the 1980's benefiting from favorable price ceilings. Offshore production levels mirror reserve addition impacts, but more gradually.

NATURAL GAS SUPPLY AND CONSUMPTION PROJECTIONS

[Quads—10^{15} Btu]

	1976 Estimate	1985		1990	
		A.G.A.	President's Program	A.G.A.	President's program
Supply:					
Lower 48	18.8	20.0	17.0	20.1	16.4
SNG from petroleum feedstocks	.3	1.2	.5	1.2	.5
Coal gasification		.4		1.6	
Alaskan gas		1.2	.1	1.2	1.2
LNG imports	.01	2.0	.6	3.0	.6
Canadian imports	.9	.6	.6	.6	.2
Total	20.0	25.4	18.8	27.7	18.9
Consumption:					
Residential and commerical	7.8		8.2		12.2
Industrial*	9.3		9.6		6.7
Electric generation	2.9		1.0		
Total	20.0		18.8		18.9

* Includes natural gas consumed and lost in transportation.

NATIONAL COSTS OF ADDITIONAL 3.1 QUADS OF ELECTRIC ENERGY

Category	Incremental energy quads [1]		Investment costs (billions of 1976 dollars)			Annual consumer costs (billions of 1976 dollars)		
	Electric	Natural gas	Electric [2]	Natural gas [3]	Difference	Electric [4]	Natural gas [5]	Difference
Residential	1.3	2.0	62.1	15.2	46.9	18.2	7.0	11.2
Commercial								
Industrial	1.8	2.8	86.1	21.4	64.7	25.2	9.6	15.6
Total	3.1	4.8	148.2	36.6	111.6	43.4	16.6	26.8

[1] Electric consumption of 3.1 quads replaced by 4.8 quads of natural gas presumes 100 percent end-use efficiency for electricity and 65 percent end-use efficiency of natural gas.

[2] Costs for additional electric capacity (50-percent nuclear and 50-percent coal with scrubbers) based on $1,100,000,000 per 1,000 MWe nuclear and $900,000,000 per 1,000 MWe coal where 1 quad electric requires 47.8×10^3 MWe of electric capacity.

[3] 4.8 quads (1.4 T ft^3 LNG, 0.4 T ft^3 coal gas, 3 T ft^3 "new" gas from deregulation) requires investment of $5,200,000,000 for coal gas, $6,400,000,000 for LNG (U.S. investment) and $25,000,000,000 for "new" gas from deregulation (presumes FPC productivity of 300 M ft^3/ft and costs per foot of $100 for high confidence, new horizon, deeper on and offshore drilling).

[4] Based on $14 per million Btu for incremental electric costs from new coal and nuclear steam electric plants.

[5] Based on $4 per million Btu for LNG, $5 per million Btu for coal gas, and $3 per million Btu for "new" natural gas from deregulation.

Economic Effects of the President's Proposed Natural Gas Users Tax

A. Introduction

One of the most important provisions in the President's energy bill (H.R. 6831 and S. 1472) in terms of possible effects on U.S. industry is a proposed excise tax on most industrial and all electric utility uses of natural gas. The purpose of this Gas Users Tax is to provide an economic incentive for the nation's electric utilities and industries (except fertilizer and certain agricultural industries) to convert from gas use to coal or other alternatives. In addition to coal conversion, the Administration expects extensive conservation benefits to occur as a result of the higher cost of gas that industries and utilities will have to pay.

The objectives of this analysis are:

To identify and explain the major provisions of the Gas Users Tax,

To assess the impact of the Tax on gas prices faced by industrial and electric utility users,

To quantify the amount of gas that will be "saved" by 1985 as a result of implementing the Tax—that is, to determine the effectiveness of the Tax in achieving its stated coal conversion objectives—and,

To estimate the overall impact of the Gas Users Tax, by itself, on the national economy.

B. Executive Summary of the Major Results of Analysis

Based on projected fuel prices and available coal conversion cost data, it is estimated that the President's proposed Industrial Gas Users Tax would provide almost no incentive to convert the vast majority of gas-using equipment to alternate fuels.

—In 1976, about 80 percent of industrial gas use, or about 5.6 trillion cubic feet (Tcf), was for process, feed-stock, direct-fired and small boiler applications. The average cost of converting these gas uses to alternate fuels is estimated to be $40 per annual million Btu (MMBtu) consumed, with a range from $6 to $500 per MMBtu. These gas uses, therefore, would not be economical to convert to alternate fuels under the President's proposed Gas Users Tax.

—The other 20 percent of industrial gas consumption (approximately 1.4 Tcf) is used in large industrial boilers that are generally less expensive to convert. Regardless of the proposed Users Tax, however, about half of this gas usage is expected to be converted to alternate fuels by 1985 as a result of curtailments because industries will not have enough gas under the President's price ceiling proposals.

—The maximum conversion from gas to other fuels that the Gas Users Tax could stimulate in industry is estimated to be somewhat less than 0.7 Tcf of the gas used in large boilers since environmental and other restrictions will preclude achievement of full conversion. Therefore, the Gas Users Tax will only stimulate conversions in a very small portion of all the gas used by the nation's industries.

Even though the Gas Users Tax would stimulate only minimal industrial conversion from gas, however, it would impose major economic costs to the nation because at least 80 percent of industrial gas will not be economical to convert, but will still be taxed.

—The Users Tax would cost U.S. industries (and indirectly cost the nation's consumers) approximately $40 billion in direct Tax payments through 1985.

—The Users Tax would raise interstate industrial gas prices in all regions of the U.S. to the equivalent price of No. 2 distillate, which varies only slightly throughout the Nation. The average increase in industrial gas prices (i.e., the Tax) by 1985 is $1.40/Mcf over projected industrial prices of gas without the Tax. For example, the tax will be large in the southern U.S. where gas prices are relatively low. But, the tax will have little impact in New England, where gas is currently higher priced because of transmission costs.

—The estimated increase in the national annual inflation rate attributable to the Gas Users Tax is about 0.3 percent with a range from 0.1 to 0.4 percent in the period from 1979 through 1984.

—Rebates proposed in connection with the Gas Users Tax are only intended to offset coal conversion expenses. Therefore, most of the estimated $40 billion direct cost to U.S. industrial gas users will be experienced as Tax, the remainder as coal conversion expenses induced by the Tax.

As a result of interstate gas curtailments and phase-out plans already in effect, remaining gas-fired electric generation by 1982 is expected to decrease from the present 3 Tcf to approximately 1 Tcf, and will be confined to intrastate markets by then, principally in four producer states: Texas, Louisiana, Oklahoma, and New Mexico. Therefore, the Gas Users Tax, which becomes effective for electric utilities beginning in 1983, is expected to affect only these four states. If conversion to alternate fuels does not occur, the estimated Gas Users Tax payments from electric utilities could equal nearly $4 billion through 1985.

C. GAS USERS TAX EFFECTS ON INDUSTRY AND THE NATION

The overall strategy of this analysis is to estimate the cost to industry of continuing to use gas with the proposed Gas Users Tax, and compare that cost with costs of using coal plus coal conversion. The major elements of this analysis are as follows:

(1) Cost of remaining with gas

The cost to industries of remaining with gas equals the future industrial gas price plus the Gas Users Tax. The Gas Users Tax was estimated on a national basis as follows (see Table 1):

TABLE 1.—PRICE EFFECTS OF INDUSTRIAL GAS USERS TAX

[Current dollars]

Year	Average distillate price to industry [2]	Tax adjustment [3]	Adjusted gas price to industry [4]	Average industrial gas price [5]	Users tax to industry [6]
1977	2.77			1.64	
1978	3.08			1.86	
1979	3.41	1.05	2.36	1.98	0.38
1980	3.65	.40	3.25	2.25	1.00
1981	3.87	.35	3.52	2.45	1.07
1982	4.08	.25	3.83	2.63	1.20
1983	4.34	.20	4.14	2.87	1.27
1984	4.55	.15	4.40	3.13	1.27
1985	4.81	0	4.81	3.41	1.40

[1] Dollars per MMBtu; all prices escalated at 5.5 percent annually.
[2] Includes crude oil equalization tax.
[3] Adjustments for industrial gas use from H.R. 6831, sec. 4992(a).
[4] For users of 1,500 MMcf per year (10^9 Btu per year) or more.
[5] Includes President's new gas ceiling price proposal.
[6] Estimated tax to be paid by industrial gas users, per MMBtu.

Average Distillate Price to Industry.—Through 1985, domestic and foreign prices were calculated using FEA price and volume projections. Then, the crude oil equalization tax contained in the Carter energy program was applied as follows:

1978: $3.50/BBL was added to the Tier 1 (old lower tier) price.

1979: The Tier I price was set equal to the Tier II (old upper tier) price.

1980 and beyond: Tier I and Tier II were set equal to the weighted average acquisition cost of all crude oil (both foreign and domestic). This weighted average included Alaskan oil as new oil; imports were assumed to account for 50% of refinery acquisitions.

After crude oil prices were obtained, an inflation-escalated distillate markup (5.5 percent per year) was added to achieve the average industrial distillate price.

Tax adjustment.—This amount was subtracted in each year in accordance with the provisions in Section 4992.

Adjusted gas price to industry.—Average distillate price to industry minus Section 4992 tax adjustment.

Average industrial gas price.—This is the national average delivered price of natural gas to industry without the Gas Users Tax. The calculation was as follows: Average wellhead prices were obtained using the Carter energy program pricing provisions for new and rollover gas. These prices were then marked up to delivered industrial prices using the national average industrial markup shown in Gas Facts[1] (1975) plus a 5.5 percent inflation adjustment annually.

Users tax to industry.—Adjusted gas price to industry minus average industrial gas price; that is, the difference between industrial gas price with and without the Users Tax, per Section 4992.

(2) *Cost of switching to coal*

The cost to industries of switching their gas use to coal depends upon the following factors:

Coal prices.—Estimates of future coal prices obtained from recent EPRI data are compared with distillate and gas prices (both taxed per the President's proposal) in Appendix A.

Large boiler conversion costs.—Estimates currently exist for conversion of one subset of this type of gas using equipment, namely large gas-fired boilers designed to burn coal (shown in Table 2). No firm basis exists at the present time to determine the costs of converting other types of large boilers to coal.

Process, feedstock, direct-fired, small boilers, and other "firm" gas uses.—Information on the cost of coal and other alternate fuel conversion is also lacking at the present time. General Motors Corporation[2] recently estimates that conversion of all of its non-large boiler gas use—which includes a representative range of process, feedstock, direct-fired, and small boiler uses—to alternate energy sources (predominantly to coal and electricity) would cost the company an average of approximately $40/MMBtu, on an annualized basis, for their entire operations. The following are illustrative of the range of conversion costs for non-boiler uses of gas:

	Per million cubic feet per year
Small paint dryers to electricity	$6
Gas preheat for heat treat furnace to electricity	40
Small heat treat carburizing furnace to electricity	500
Facility for generating nitrogen from air to replace gas in the heat treat process	6

TABLE 2.—ESTIMATED COAL CONVERSION COSTS FOR LARGE CONVERTIBLE GAS-FIRED BOILERS[1]

[Current dollars]

Boiler size (MMBtu per hour)	Cost of coal conversion		Annualized cost of coal conversion per MMBtu	
	1976	1985	1976	1985
100	800,000	1,900,000	0.18	0.48
250	1,300,000	3,100,000	.12	.26
500	2,700,000	6,500,000	.12	.26
1,000	4,800,000	11,600,000	.10	.21
2,000	8,200,000	19,800,000	.08	.19

[1] Minimum conversion costs for combustors that were originally coal-burning units, or were designed with future coal burning in mind.

Sources: NUS Corp., "Analysis of the Prevailing and Projected Environmental Costs for Coal Conversion of Major Fuel Burning Installations," prepared for FEA Office of Coal Utilization, October 1976; Gilbert Associates, "Analysis of Cost for Coal Conversion," prepared for FEA Office of Coal Utilization, October 1976.

[1] American Gas Association, 1975 Gas Facts, Arlington, Virginia (1976).
[2] Ricca, John (Manager, Energy Resources, General Motors Corporation), "The Economics of Energy (Natural Gas) Impact on Industry," speech presented at University of Nebraska, Omaha, April 6, 1976.

TABLE 3.—CURRENT NATURAL GAS CONSUMPTION BY PROIRITY OF SERVICE

FPC service priority [1]	1974 actual		1975 actual		1976 estimate	
	T ft³	Percent	T ft³	Percent	T ft³	Percent
1: Residential and small commercial (less than 50 M ft³ on a peak day)	6.1	31.9	6.1	34.5	6.2	35.6
2–5: Large commercial and industrial firm usage	6.7	35.1	6.3	35.6	6.1	35.0
6–7: Interruptible small (less than 3,000 M ft³) industrial usage	.8	4.2	.6	3.4	.5	2.9
8–9:						
Interruptible large (greater than 3,000 M ft³ per day) industrial usage	1.8	9.4	1.4	7.9	1.4	8.0
Firm electric (primarily intrastate) production	2.2	11.5	2.0	11.3	2.0	11.5
9: Interruptible electric production (primary interstate)	1.2	6.3	1.1	6.2	1.0	5.7
Other (sales to municipalities)	.3	1.6	.2	1.1	.2	1.1
Total consumed by end user	19.1	100.0	17.7	100.0	17.4	100.0
Field use	2.4		2.3		2.4	
Total marketed production	21.6		20.1		19.8	

[1] Defined in appendix C.

Sources: "Future Gas Consumption in the United States," (Vol. 6 and supplement) by the gas requirements committee; "Impact of Natural Gas Curtailments on Electric Utility Plants," prepared for U.S. EPA.

Note: Percent totals may not add to 100 due to rounding.

(3) Maximum coal conversion assumptions

Current use of natural gas in the United States is shown by FPC service priority groups in Table 3. It is shown that 8.0 trillion cubic ftet (Tcf) of natural gas was consumed by industries and large commercial users in 1976 (Priorities 2 through 9 excluding electric utility use).

Excluding approximately 1 Tcf of gas used by large commercial users, about 80 percent of this gas use was for "firm" and small boiler applications. It is assumed that none of this gas will be economical to convert as a result of the Gas Users Tax. The reason for this finding is that the costs of converting process, feedstock, space heat, small boilers and other "firm" industrial uses of gas (described in Point 2, above) are considerably higher than the projected difference between coal prices and natural gas prices (shown in Appendix A).

The remaining 1.4 Tcf of industrial gas use—about 20 percent—is for large gas-fired industrial boilers. The only avaibale coal conversion data for large boilers (summarized in Table 2) reflects costs of converting only a small portion of this group as outlined in Point 2, above. Furthermore, this group of boilers consists of the least costly equipment to convert. Data is presently not available on two essential points, however: (a) the proportion of large boiler use represented by this group, and (b) the cost of converting all other kinds of large industrial gas-fired boilers constituting FPC Priorities 8 and 9. At the present time, therefore, it is not possible to estimate the actual portion of the 1.4 Tcf of gas which would be displaced by conversions induced by the Gas Users Tax. Conversion of the entire 1.4 Tcf of gas used in large industrial boilers will not be induced by the Tax, however, for the following important reasons:

(*a*) Between now and 1985 projected natural gas curtailments, with or without a Gas Users Tax, are expected to result in a decline in industrial gas use of 0.7 Tcf (predominantly from large boilers).[8] These curtailments result from natural gas unavailability caused by government price regulation, and would also

[8] Gas Requirements Committee, *Future Gas Consumption of the United States*, University of Denver Research Institute, Denver, Colorado (Volume 6, December 1975 and Supplement, September 1976).

occur under the President's proposed $1.75 new gas price proposal which fails to stimulate additional gas supply by 1985.[4]

(*b*) Other reasons exist which could constrain industrial users from converting large boilers, even if an economic incentive is created by the Gas Users Tax. These reasons include environmental constraints, inability to obtain either capital or coal, monopoly market position and convenience.

Therefore, it is estimated that the maximum quantity of gas "saved" attributable to large boiler conversions induced by the Gas Users Tax in somewhat less than 0.7 Tcf.

(*4*) *Direct cost to U.S. of gas users tax*

Table 4 shows the estimated direct costs and rebates of U.S. industries resulting from the proposed Gas Users Tax by 1985. The basis for these calculations was as follows:

—The full Users Tax on gas for industries will only apply to corporations whose use of gas exceeds 1,500 MMcf per year. Medium-size companies—those whose annual gas use is between 500 and 1,500 MMcf—will be taxed not less than 50 percent at 500 MMcf and rising incrementally to 100 percent at 1,500 MMcf and more per year. Industrial companies whose gas use is less than 500 MMcf per year will not experience the Gas Users Tax.

—Since the Users Tax does not apply to all industrial users equally, it was necessary to determine a weighted average price for use in calculating the total tax. This was done by assuming that approximately 80 percent of industrial users subject to the tax would pay the tax on all gas consumption and assuming that the other 20 percent were evenly distributed throughout the usage scale (500 Mcf to 1,500 Mcf).[5]

—The weighted average tax was then multiplied by the forecasted industrial demand volume affected by the tax. This volume was derived by reducing volumes subject to the tax by those industrial demand volumes where is was estimated that industry would economically switch to alternate fuels, given the gas price including tax.

Since all large gas-fired boilers used in industry are assumed to switch to coal as a result of the Users Tax, the $40 billion cumulative cost by 1985 reflects a minimum estimate. Any delay in these conversions would only increase the cumulative amount of Tax paid by U.S. industries.

TABLE 4.—DIRECT COST OF INDUSTRIAL GAS USERS TAX

Year	Weighted unit tax (dollars per M ft³)[1]	Taxable volume of industrial gas use (T ft³)[2]	Minimum total direct cost of user tax (billions)
1979	0.36	6.9	$2.5
1980	0.92	5.8	5.3
1981	0.99	5.7	5.6
1982	1.11	5.6	6.2
1983	1.18	5.6	6.6
1984	1.16	5.7	6.6
1985	1.29	5.4	7.0
Total			39.8

[1] Users tax weighted to reflect lower percentage of tax paid for smaller industrial gas consumers (reference H.R. 6831, sec. 4992).

[2] Gas requirements committee, "Future Gas Consumption of the United States," University of Denver Research Institute, Denver, Colo. (vol. 6, December 1975, and supplement, September 1976), less estimated maximum reduction in gas volumes attributable to gas users tax.

A second major impact of the Gas Users Tax is the substantial national standardization of gas cost to industries. Table 5 lists gas price percentage increases over 1976 prices by region for 1980 and 1985. The effects upon the various regions of the country are markedly different. Industrial users in New England will experience an increase of 29 percent by 1980, for example, while users in the South Atlantic states will see an increase of 167 percent by 1980.

[4] American Gas Association, *Impact of the President's Proposed $1.75/Mcf of New Gas Price Ceiling on Domestic Gas Production*, Arlington, Va. (1977).

[5] American Gas Association, *1975 Gas Facts, supra*—80/20% split adapted from ratio of Large Volume Sales to Total Commercial Industrial and "Other" industrial sales, page 85.

The direct costs of the Gas Users Tax will fall predominantly on those Major Industrial Groups shown in Table 6 whose use of gas includes extensive firing of large boilers.

(6) The Wharton Econometrical Annual Model, with energy sectors disaggregated, was used to determine the macroeconomic effects of the Gas Users Tax. A baseline case was prepared which simulated the effects of the President's energy bill, excluding the effects of the Gas Users Tax. The effects of the Tax were then simulated on top of the baseline. Table 7 provides the relevant results which, in summary are as follows:

The increase in the annual inflation rate is estimated to be 0.3 percent with a range from 0.1 to 0.4 percent in the period from 1979 to 1984. Due to equilibrating reactions of the economy and the non-continuous phase-in of the tax, the percentage increase dips to +0.1 in 1981 and peaks at +0.4 percent in 1983.

Unemployment is estimated to increase only slightly. This is due to the relatively small value-added contribution to GNP of natural gas (less than 2 percent) and the already high unemployment rate in the baseline case.

GNP growth is also only slightly curtailed. This is again due to the relatively small portion of GNP attributable to natural gas.

It should be emphasized that these calculations reflect the effect of the Gas Users Tax when superimposed on H.R. 6831 as an economic baseline (exclusive of the Gas Users Tax), which itself includes marked inflation, GNP, and unemployment effects. The results also included price increases of electric power induced by the Users Tax (see below).

TABLE 5.—REGIONAL INCREASES IN INDUSTRIAL GAS PRICES OVER CURRENT (1976) PRICES RESULTING FROM USERS TAX

Census region	1980 increases percent over 1976 price	1985 increases percent over 1976 price
1. New England	29	91
2. Mid-Atlantic	95	189
3. South Atlantic	167	295
4. East North Central	135	249
5. West North Central	262	436
6. East South Central	215	368
7. West South Central	149	270
8. Mountain	244	411
9. Pacific	124	232

[1] 1976 prices were obtained from AGA data (gathered in preparation for the 1977 Gas Facts) while 1980 and 1985 prices are those shown for the appropriate PAD's in appendix A.

TABLE 6.—ESTIMATED 1975 GAS USE IN INDUSTRY

[Billion cubic feet]

SIC code	Largest energy—Using industries [1]	Total gas use [1]	Large boiler use [2]
20	Food	370	0
26	Paper	310	250
28	Chemicals	1,640	470
29	Petroleum	890	0
30	Rubber, plastics	70	20
32	Stone, clay, glass	510	0
331-332	Primary iron and steel	780	350
333-339	Primary nonferrous	380	0
34	Fabricated metals	160	0
37	Transportation equipment	160	0
	All other manufacturing industries	1,800	320
	Industry total	7,070	1,400

[1] Gas requirements committee, "U.S. Gas Consumption in 1975 (supplement to vol. 6, September 1976).
[2] American Gas Association, "Survey of Industrial Gas End Uses," Arlington, Va. (1976) and industry discussion.

TABLE 7.—MACROECONOMIC IMPACTS OF INDUSTRIAL GAS USERS TAX[1]

	Annual rate (percent)						
	1979	1980	1981	1982	1983	1984	1985
Inflation:							
Base	5.9	6.5	5.8	5.3	5.6	5.3	5.4
Change	+.2	+.3	+.1	+.3	+.4	+.2	0
Unemployment:							
Base	7.6	7.6	7.1	6.9	6.6	5.8	5.4
Change	0	+.1	+.1	0	+.1	+.2	+.1
GNP:							
Base	3.1	4.1	4.4	3.9	3.4	4.0	3.8
Change	0	−.1	0	−.1	−.2	−.1	+.1

[1] Calculations based on Wharton econometric annual model (disaggregation of energy sector), using President's proposed industrial gas tax.

D. GAS USERS TAX EFFECTS ON ELECTRIC UTILITIES

As Table 8 shows, the procedure by which the Utility Gas Users Tax is calculated is the same as the procedure for industrial gas prices. A key difference is that the Section 4092 Tax Adjustment (i.e., the User Tax) for utilities is not to begin until 1983. Major results are as follows:

This portion of the Gas Users Tax is only expected to affect intrastate use of natural gas for the generation of electricity since all recent projections show a decline in interstate demand to nearly 0 by 1982 due to planned phase-outs.[5,6] Demand is also being reduced in the intrastate market by state regulatory policy. For example, the Texas Railroad Commission has promulgated Order Number 600 (1975) that will reduce state electric utility gas usage to 15 percent of current levels by 1990. (Texas currently consumes 37 percent of all gas used in generation of electricity.)

Intrastate use of natural gas for electric utilities is still projected to exceed 1 Tcf in 1982 and beyond despite limiting regulations in several producer states. Nearly all of this usage will be concentrated in intrastate markets of Texas, Louisiana, Oklahoma, and New Mexico. The impact of the Utility Gas Users Tax will, therefore, be confined to these four states. If conversion does not occur the tax payments will be nearly $4 billion through 1985.

If high sulfur coal is available to the intrastate utilities, it is estimated that utilities in all four states will find it economical to switch gas boilers to coal (see Table 9). However, if only low sulfur coal is available, utility gas users will prefer to remain with gas and pay the Users Tax on an economic basis because low sulfur coal is costlier than high-sulfur coal and must also be scrubbed according to the President's proposed National Energy Plan.

TABLE 8.—PRICE EFFECTS OF ELECTRIC UTILITY USERS TAX[1]

Year	National average distillate price to electric utilities[2]	Tax adjustment[3]	Adjusted gas price to electric utilities	National average gas price[4]	Users tax
1977	2.77			1.42	
1978	3.08			1.63	
1979	3.41			1.74	
1980	3.65			2.00	
1981	3.87			2.19	
1982	4.08			2.36	
1983	4.34	.050	3.84	2.59	1.25
1984	4.55	.50	4.05	2.84	1.21
1985	4.81	.50	4.31	3.12	1.19

[1] Dollars per MMBtu all prices escalated at 5.5 percent annually.
[2] Includes crude oil equalization tax.
[3] H.R. 6831, sec. 4992.
[4] Includes new gas ceiling price proposal.

[5] American Gas Association, *Gas Utility Industry Projections to 1990*, Arlington, Virginia, September 1976.

[6] Foster Associates, *Impact of Natural Gas Curtailments on Electric Utility Plants*, prepared for U.S. Environmental Protection Agency, August 1975.

TABLE 9.—ESTIMATED COSTS OF UTILITY COAL CONVERSION VERSUS NATURAL GAS AND COAL PRICES

[Current dollars per MMBtu annually]

Year	Fuel price projections			Differences between projected prices of natural gas and coal		Estimated costs of coal conversion [4]
	Distillate [1]	Natural gas [2]	Low sulfur coal [3]	High sulfur coal	Low sulfur coal	
1982	4.38	2.36	1.78	1.47	0.58	1.90
1983	4.69	3.79	2.07	3.86	1.73	2.00
1984	4.94	4.99	2.39	3.00	1.60	2.12
1985	5.27	4.27	2.80	4.34	1.47	2.23

[1] Industrial distillate price for PAD 3 from appendix A.
[2] Includes President's proposed $1.75 ceiling price for new natural gas.
[3] Foster Associates, "Fuel and Energy Price Forecasts," prepared for Electric Power Research Institute, Palo Alto, Calif. (EPRI Report No. EA-411, March 1977).
[4] Bechtel Power Corp., "Coal-Fired Powerplant Capital Cost Estimates," prepared for Electric Power Research Institute, Palo Alto, Calif. (EPRI Report No. AF-342 January 1977).

APPENDIX A

DELIVERED INDUSTRIAL FUEL PRICE PROJECTIONS

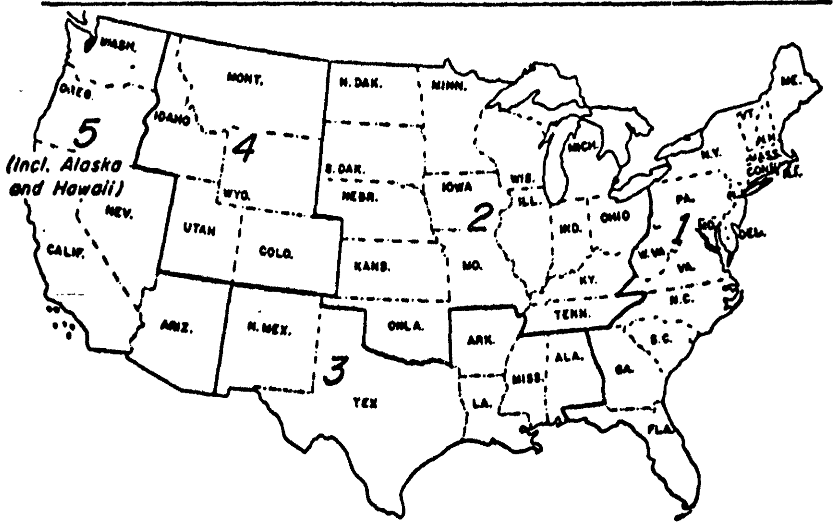
[Cost in current dollars per million Btu]

Year	Distillate	Natural gas	Coal	Differential between coal and natural gas prices
PAD I:				
1977	2.84	1.64	1.02	0.62
1978	3.15	1.86	1.23	.63
1979	3.65	2.45	1.44	1.01
1980	4.04	3.34	1.66	1.68
1981	4.26	3.61	1.81	1.80
1982	4.53	3.93	2.13	1.80
1983	4.85	4.25	2.39	1.86
1984	5.11	4.51	2.66	1.85
1985	5.44	4.94	2.74	2.20
PAD II:				
1977	2.80	1.64	.84	.80
1978	3.10	1.86	1.03	.83
1979	3.60	2.40	1.23	1.17
1980	3.99	3.29	1.44	1.85
1981	4.21	3.56	1.66	1.90
1982	4.47	3.87	1.84	2.03
1983	4.79	4.19	2.13	2.06
1984	5.05	4.45	2.39	2.06
1985	5.18	4.88	2.35	2.53
PAD III:				
1977	2.73	1.64	.83	.80
1978	3.03	1.86	1.06	.80
1979	3.52	2.32	1.29	1.03
1980	3.91	3.21	1.54	1.67
1981	4.12	3.47	1.81	1.66
1982	4.38	3.78	2.09	1.69
1983	4.69	4.09	2.38	1.71
1984	4.94	4.34	2.70	1.64
1985	5.27	4.77	2.84	1.93
PAD IV:				
1977	2.78	1.64	.70	.94
1978	3.08	1.86	.83	1.03
1979	3.58	2.38	.97	1.41
1980	3.97	3.27	1.11	2.16
1981	4.19	3.64	1.26	2.38
1982	4.45	3.85	1.42	2.43
1983	4.76	4.16	1.60	2.56
1984	5.02	4.42	1.77	2.65
1985	5.35	4.85	1.97	2.88
PAD V:				
1977	2.78	1.64	1.17	.47
1978	3.08	1.86	1.33	.53
1979	3.58	2.38	1.50	.88
1980	3.97	3.27	1.69	1.58
1981	4.19	3.64	1.88	1.76
1982	4.45	3.85	2.08	1.77
1983	4.76	4.16	2.30	1.86
1984	5.02	4.42	2.52	1.90
1985	5.35	4.85	2.65	2.20

Sources: FEA, Monthly Petroleum Product Price Report. Foster Associates, Fuels and Price Forecasts, EPRI No. EA-411 March 1977 A.G.A., Gas Facts.

APPENDIX B

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS



Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States and Puerto Rico."

APPENDIX C

FPC SERVICE PRIORITIES FOR NATURAL GAS

Order of preference and end use of gas

1 Residential, small commercial (less than 50 Mcf on a peak day).
2 Large commercial requirements (50 Mcf or more on a peak day) firm industrial requirements for plant protection, feedstock and process needs, and pipeline customer storage injection requirements,
3 All industrial requirements not specified in (2), (4), (5), (6), (7), (8), or (9),
4 Firm industrial requirements for boiler fuel use at less than 3,000 Mcf per day, but more than 1,500 Mcf per day, where alternate fuel capabilities can meet such requirements.
5 Firm industrial requirements for large volume (3,000 Mcf or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements.
6 Interruptible requirements of more than 300 Mcf per day; but less than 1,500 Mcf per day, where alternate fuel capabilities can meet such requirements,
7 Interruptible requirements of intermediate volumes (from 1,500 Mcf per day through 3,000 Mcf per day), where alternate fuel capabilities can meet such requirements,
8 Interruptible requirements of more than 3,000 Mcf per day, but less than 10,000 Mcf per day, where alternate fuel capabilities can meet such requirements.
9 Interruptible requirements of more than 10,000 Mcf per day, where alternate fuel capabilities can meet such requirements.

Source: Federal Power Commission's Order No. 467-B in Docket No. R-469, dated March 2, 1973, pertaining to the Utilization and Conservation of Natural Resources—Natural Gas Act.

EFFECTS OF THE HOUSE WAYS AND MEANS COMMITTEE REVISIONS IN THE PRESIDENT'S PROPOSED GAS USERS TAX

INTRODUCTION

The President's proposed natural Gas Users Tax has been substantially modified by the House Ways and Means Committee in recent weeks. The purpose of this analysis is to estimate the effects of these modifications in terms of direct costs to the nation's industries.

EXECUTIVE SUMMARY

The Gas Users Tax would now apply to only three categories of use: electric generation, industrial boilers, and certain other non-exempt industrial processes. A number of industrial uses of gas are now to be specifically exempted from the tax with the result that a far smaller quantity of gas (about 3 Tcf instead of up to 7.1 Tcf under the President's proposal) would be affected by the revised tax.

Based on A.G.A.'s previous analysis of the likelihood of industrial conversions under the President's original proposal, the Ways and Means Committee appears to have only retained portions of the Users Tax that might actually stimulate some measure of either conservation or boiler conversions to coal.

The direct cost of the revised Gas Users Tax to U.S. industries is estimated to be less than $14 billion cumulatively by 1985, which is substantially lower than the estimated $40 billion direct cost of the President's proposed version of the tax.

Under the incremental pricing provisions adopted by the House Interstate and Foreign Commerce Committee, it is estimated that natural gas prices for industrial users would become equivalent to distillate prices in 7 of the 10 Federal Census regions by 1980, and in all regions of the U.S. by 1982. As the Users Tax is only to be assessed on industrial gas purchased at less than this Btu equivalency price, it is concluded that no Users Tax would be paid in seven regions after 1980, and anywhere in the U.S. after 1982.

MAJOR MODIFICATIONS TO THE USERS TAX

The natural gas Users Tax reported to the House by the Ways and Means Committee on July 15, 1977, is substantially more limited than the President's original proposal. The limitations have been added in an attempt by the committee to reduce the burdens imposed by the Tax while retaining some of the more effective portions of the basic proposal.

The Gas Users Tax is now to be imposed in several degrees of severity depending on the conversion or conservation prospects of the various industrial uses of natural gas. Consistent with this philosophy, the current version exempts from any tax those uses of gas which do not lend themselves either to conservation or to conversion to alternate fuels. These exempted uses include: residential; transportation (including pipelines); farming; commercial establishments; oil exploration, development, storage; and other industrial process uses "where there is no substitute fuel—

(a) which may be used without materially and adversely affecting the manufacturing process or the quality of the manufactured goods, and

(b) the use of which is economically and environmentally feasible." [1]

Specific industrial processes that will be tax-exempt cannot be identified with any precision until the new Department of Energy has completed its rule-making in connection with the proposed Tax. The process exemption is likely to encompass most industrial process uses of natural gas because the only alternate fuel available to most processes is electricity, which should generally be excluded by the "economical" requirement. This is because conversion of process uses of gas to alternate fuels (electricity or coal) is estimated to average $40/Mcf on an annualized basis.[2]

Remaining industrial and utility uses of gas are non-exempt, and are taxed at three different rates (Tiers 1 through 3) as follows:

Tier 3 is the tax schedule applicable to gas used for generating electricity for resale. Table 1 shows the application of this Tier of the tax. The tax is limited so that the industrial price of gas will not exceed the Btu equivalent price of residual fuel oil, as shown in Table 1.

The Tier 2 tax rate, illustrated in Table 2, is intended to apply to industrial gas "use in a boiler or in a turbine . . .". Tier 2 uses will incur the highest Users Tax as these can most often be converted to alternate fuels economically. The high tax on this tier is to motivate such conversions.

The Tier 1 tax rate is also shown in Table 2. This rate is to apply to all uses which are neither exempt, nor classified in Tiers 2 and 3. It is not clear how much gas use will be covered by this tier because clarification of the other categories through rule-making is required. Nonetheless, the quantity should be

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[1] House Ways and Means Committee Report on H.R. 6831, July 15, 1977.

[2] American Gas Association. *Economic Effects of the President's Proposed Natural Gas Users Tax*, Arlington, Virginia (1977).

quite small, consisting basically of a few process uses for which the form value [3] is low (e.g., lime kilns). Tiers 1 and 2 are still calculated with reference to a target price based on distillate as in the original proposal. (Effectively establishing a ceiling price for gas).

These tax schedules are intended to apply to all corporate uses of gas in excess of 290 MMcf per year. The revised version has also eliminated the variable part of the original Users Tax that depended on the quantity of gas used.

Finally, all gas purchased under interruptible contracts is subject to a tax that is 10 percent less than the amount that would otherwise be paid.

DIRECT COST OF THE TAX

Because exact data on industrial gas usage categories is not available, the following analysis is based on a combination of available data and A.G.A. estimations. Additionally, to the extent that conservation may reduce the taxable use of gas, these estimates may be high. Available data do not permit estimation of the conservation effects, thus this potential reduction in the Users Tax is not included in the following analysis.

Tier 1 volumes (medium form values) would seem to be very small, thus the estimate of direct cost is confined to Tiers 2 and 3.

TABLE 1.—PRICE EFFECTS OF TIER 3 (ELECTRIC UTILITY) GAS USERS TAX [1]

[Current dollars]

Year	National average [2] gas price	Users tax	Adjusted gas price to electric utilities	National average [3] residual price to electric utilities
1977	1.42			1.77
1978	1.63			2.08
1979	1.74			2.41
1980	2.00			2.65
1981	2.19			2.87
1982	2.36			3.08
1983	2.59	0.55	3.14	3.34
1984	2.84	.65	3.49	3.55
1985	3.12	.75	3.87	3.81

[1] Dollars per MMBtu; all prices escalated at 5.5 percent annually.
[2] Assumes President's proposed $1.75 new gas ceiling price proposal.
[3] Calculated from FEA data including crude oil equalization tax.

TABLE 2.—PRICE EFFECTS OF TIERS 1 AND 2 (INDUSTRIAL) GAS USERS TAX [1]

[Cost in current dollars]

Year	Average distillate price to industry [2]	Tax adjustment [3]		Adjusted gas price [4]		Adjusted industrial gas price [5]	Users tax [6]	
		Tier 2	Tier 1	Tier 2	Tier 1		Tier 2	Tier 1
1977	2.77					1.64		
1978	3.08					1.86		
1979	3.41	1.05	1.35	2.36	2.06	1.98	0.38	0.08
1980	3.65	.40	.70	3.25	2.95	2.25	1.00	.70
1981	3.87	.35	.65	3.52	3.22	2.45	1.07	.77
1982	4.08	.25	.55	3.83	3.53	2.63	1.20	.90
1983	4.34	.20	.50	4.14	3.84	2.87	1.27	.97
1984	4.55	.15	.45	4.40	4.10	3.13	1.27	.97
1985	4.81	0	.30	4.81	4.51	3.41	1.40	1.10

[1] Dollars per million Btu; all prices escalated at 5.5 percent annually.
[2] Calculated from FEA data and includes crude oil equalization tax.
[3] Adjustments for industrial gas use from H.R. 6831, sec. 4992(a).
[4] For users of 290 MMcf/Year (10^9 Btu per year) or more.
[5] Based on President's new gas ceiling price proposal.
[6] Estimated tax to be paid by industrial gas users, per MMBtu.

[3] Form value is a method of measuring the necessity of using gas. For example, a high form value would be attributed to a process requiring exact flame control, while boiler use has the lowest form value since heat is the only attribute of gas that is used.

Tier 2, which includes all boiler uses not covered by the 200 MMcf/year exemption, applies against a total of approximately 3 Tcf of gas used in the entire (large and small) boiler market.[4]

This taxable quantity is expected to be reduced somewhat over the next few years.[5] Gas Requirements Committee data [6] suggest that 0.7 Tcf will be eliminated by 1985 as the result of ongoing curtailments. In previous analysis, A.G.A. suggested that a maximum of 0.7 Tcf might also be converted by that year due to a Users Tax. Data recently acquired from the American Boiler Manufacturers Association suggest that the actual quantity lies somewhat below this maximum. Since some boilers, such as those targeted by the ESECA [7] program, are likely to be converted a realistic range for all tax-induced conversions is 0.3 to 0.7 Tcf.

The American Boiler Manufacturers Association [8] suggests that a coal-fired industrial boiler of 200,000 lb/hour (2600 Mcf/day) capacity would cost $12.3 million in 1977 dollars. A mandatory flue gas desulfurization (FGD) unit in accordance with provisions of the 1977 Clean Air Act Amendments would add another $4 to $5 million to the base cost. These estimates do not include costs associated with site preparation, which can be substantial because a coal-fired boiler can require up to five times the area of a gas plant. The cost of such a boiler without FGD translates to $1.32/Mcf annualized (1980 dollars), which is close to the difference between the unit costs of coal and gas (after the Users Tax, Tier 2). The FGD unit would make construction and operation of this coal plant even more expensive than continued operation of a gas fired boiler, even with paying the tax. Conversion of all large boilers through the incentive of this tax, therefore, appears unlikely. Payment of the Users Tax on a remaining 1.6 to 2 Tcf of boiler fuel would result in a total of $12.1 to $14.2 billion of tax to be collected by 1985.

Other factors, however, reduce the direct Users Tax assessments even further. For example, it is estimated that the incremental pricing provisions currently under consideration by the Congress would end tax payments in all but three federal census regions by 1980, and in all regions of the U.S. by 1982. These price provisions would cause the price of gas delivered to industrial users to increase to the price of distillate rapidly over the next several years. Since the price of distillate is the target price used in calculating the tax, no tax is paid when the distillate Btu equivalency price is paid for gas.

As shown in Table 3, only the East North Central and both South Central districts will pay a tax in 1980 while none is expected to in 1985. The tax collected through 1980 in these districts would be less than $1 billion.

The tax paid by the electric utilities does not appear to be high enough to create an increased incentive for conversion. This is because converting a gas fired electric plant to coal essentially requires building a new plant. The tax will, therefore, probably be paid on the remaining 1 Tcf of gas expected to be used in generation of electricity by 1985. This would result in $1.95 billion of taxes paid through 1985. If incremental pricing is required for electric utility consumption this tax would be reduced to near zero.

TABLE 3.—COMPARISON OF TARGET PRICES WITH INCREMENTALLY PRICED INDUSTRIAL NATURAL GAS

[Dollar cost in million Btu's]

Census region	Industrial gas price [1]		Tier 2 target price	
	1980	1985	1980	1985
Northeast	3.54	4.94	3.14	4.94
Middle Atlantic	3.54	4.94	3.14	4.94
East North Central	2.80	4.68	3.09	4.68
West North Central	3.49	4.68	3.09	4.68
South Atlantic	3.54	4.94	3.14	4.94
East South Central	2.71	4.77	3.01	4.77
West South Central	2.84	4.77	3.01	4.77
Mountain	3.47	4.85	3.07	4.85
Pacific	3.47	4.85	3.07	4.85

[1] 1985 tax on tier 1 is $0.60 per million Btu and on tier 2, $1.10 per million Btu.

[4] See Appendix. Estimate from small and large industrial categories (FPC priorities 2–5 and 6–9).

[5] A.G.A., *Supra.*

[6] Gas Requirements Committee, *Future Gas Consumption of the United States;* University of Denver Research Institute, Denver, Colorado (Volume 6, December 1975 and supplement, September 1976).

[7] Energy supply and Environmental Coordination Act—one purpose of this program is to convert boilers which are designed to burn coal but are currently burning natural gas.

[8] Conversation with William Marks, President of American Boiler Manufacturers Association.

APPENDIX

CURRENT NATURAL GAS CONSUMPTION BY PRIORITY OF SERVICE

FPC service priority	1974 actual T ft³	1974 actual Percent	1975 actual T ft³	1975 actual Percent	1976 estimate T ft³	1976 estimate Percent
1: Residential and small commercial (less than 50 M ft³ on a peak day)	6.1	31.9	6.1	34.5	6.2	35.6
2-5: Large commercial and industrial firm usage	6.7	35.1	6.3	35.6	6.1	35.0
6-7: Interruptible small (less than 3,000 M ft³ per day industrial usage)	.8	4.2	.6	3.4	.5	2.9
8-9: Interruptible large (greater than 3,000 M ft³ per day industrial usage)	1.8	9.4	1.4	7.9	1.4	8.0
Firm electric (primarily intrastate) production	2.2	11.5	2.0	11.3	2.0	11.5
9: Interruptible electric production (primarily interstate)	1.2	6.3	1.1	6.2	1.0	5.7
Other (sales to municipalities)	.3	1.6	.2	1.1	.2	1.1
Total consumed by end user	19.1	100.0	17.7	100.0	17.4	100.0
Field use	2.4		2.3		2.4	
Total marketed production	21.6		20.1		19.8	

Sources: "Future Gas Consumption in the United States" (vol. 6 and supplement) by the gas requirements committee; "Impact of Natural Gas Curtailments on Electric Utility Plants," prepared for U.S. EPA.

Note: Percent totals may not add to 100 due to rounding.

DRILLING ACTIVITY AND POTENTIAL GAS RESOURCES

A. INTRODUCTION

One of the major contentions of opponents of deregulation of the wellhead price of new natural gas is that the natural gas resource base will not support continued production at current levels even at significantly increased wellhead prices. This conclusion is largely based on the continued decline in reserves at a time when gas well completions are at an all-time high.

This paper provides an analysis which reconciles declining reserves and large potential resource estimates in light of gas well drilling activity.

B. EXECUTIVE SUMMARY OF RESULTS OF ANALYSIS

While total gas well completions in the U.S. in 1975 were at an all-time high, over 80 percent of the gas wells completed were developmental as opposed to exploratory.

Further, exploratory well drilling has shown a consistent downward trend since the late 1950's (after federal wellhead price regulation was authorized) and has only in the past four years begun to show signs of some increase, although it is, at present, still only 60 percent of its peak level reached in 1956.

Reserve additions have continued to decline largely because the predominance of drilling and well completions is in older, less risky, and less costly areas. These areas are generally onshore and at shallow to moderate well depths.

In 1975, more than 90 percent of all gas wells completed were onshore and at depths of less than 15,000 feet. Furthermore, the drilling cost associated with these wells averaged only about \$35/ft and the percentage of wells drilled that were successful was about 65 percent.

By contrast, only 10 percent of gas well completions were generally in offshore or deep onshore areas (deeper than 15,000 feet) where drilling costs averaged well over \$100/ft and the success percentage was about 50 percent.

From the standpoint of the location of U.S. potential gas resources, which are estimated to be in the 600–900 Tcf range (in addition to proved reserves of 216 Tcf), the predominance of drilling activity and well completions has not been in areas containing this potential which is generally in deep onshore areas, in offshore areas, and in Alaska.

For example, about 90 percent of all gas wells completed in 1975 were in areas and at depths where only 30 percent of the estimated potential gas resource exists.

Even in the case of exploratory gas well activity, less than 4 percent of the gas well completions were in areas with over 50 percent of the estimated potential resource.

Moreover, as further evidence that drilling activity is largely in historical production areas rather than in new frontier areas, almost 90 percent of all well completions in 1975 were in areas accounting for 50 percent of the current U.S. gas production.

It is also clear that the predominance of drilling activity in older, less risky, and inexpensive areas is related closely to economic factors:

About 93 percent of all gas wells completed in 1975 were in generally shallow, onshore areas where the drilling costs were less than $50/ft.

However, from 1975 drilling and cost data, over 60 percent of the estimated potential gas resource is in areas that required more than $50/ft for a completed well.

Finally, the fact that only 4 percent of the total wells completed in 1975 were in offshore areas and only an additional 3 percent were in deep onshore areas suggests that:

the lack of economic incentive in the interstate market as a result of continued wellhead price regulation has been a deterrent to higher cost development in frontier areas.

there is not sufficient availability of offshore federal lease tracts in view of the significant potential resources in these areas.

C. DRILLING HISTORY

Exploratory well drilling[1] has declined significantly since 1956 as shown in Chart 1. While the number of exploratory wells drilled has increased some since 1971, only a fraction of the decrease experienced since 1956 has been recovered. In contrast, developmental well completions peaked briefly in 1961 and then declined until the recent increase which started in 1972 and has since reached record levels.

Recent drilling for gas has been characterized by the following phenomena:

Finding rates (natural gas volumes found per foot drilled) are generally declining.

Drilling costs are steadily rising resulting in a decline in gas volumes found per dollar of exploration investment.

Gas well drilling and well completions have increased dramatically starting in 1972.

Productivity (Mcf/ft) has been steadily declining since 1967.

These drilling indicators have been interpreted by some as indicating the onset of resource depletion.

D. DATA SOURCES

Four primary sources of data were used in this study; the 1975 Joint Association Survey of the United States Oil and Gas Producing Industries; the Quarterly Review of Drilling Statistics for the United States, 1975; the Potential Supply of Natural Gas in the United States; and the Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1975. All of the various sources of data were used by restricting the analysis to 1975. Each of the reference documents contain 1975 statistics except for the Potential Supply of Natural Gas in the United States. It contains data as of December 31, 1972. Material from the Potential Gas Committee's 1976 estimates, which are as yet unpublished, was used to update this report.

Because the potential estimates of natural gas in the United States are reported in 12 geographic areas as shown in Figure 1, this analysis examines these 12 geographical areas and 27 drilling regions. The drilling regions subdivide the geographic areas into onshore, offshore as well as deep (greater than 15,000 feet) and shallow to moderate depths.

Gas well completions were available by depth of well only in the Joint Association Survey report so this information could be related to the potential for each drilling region. Unfortunately, developmental gas well completions and exploratory completions are not tabulated by depth. Similarly proved reserves and natural gas production data are not available by depth of well.

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[1] An exploratory well is a well drilled (1) to find gas in an unproved area; (2) to find new reservoirs in a known field; or (3) to extend the limits of a known gas reservoir.

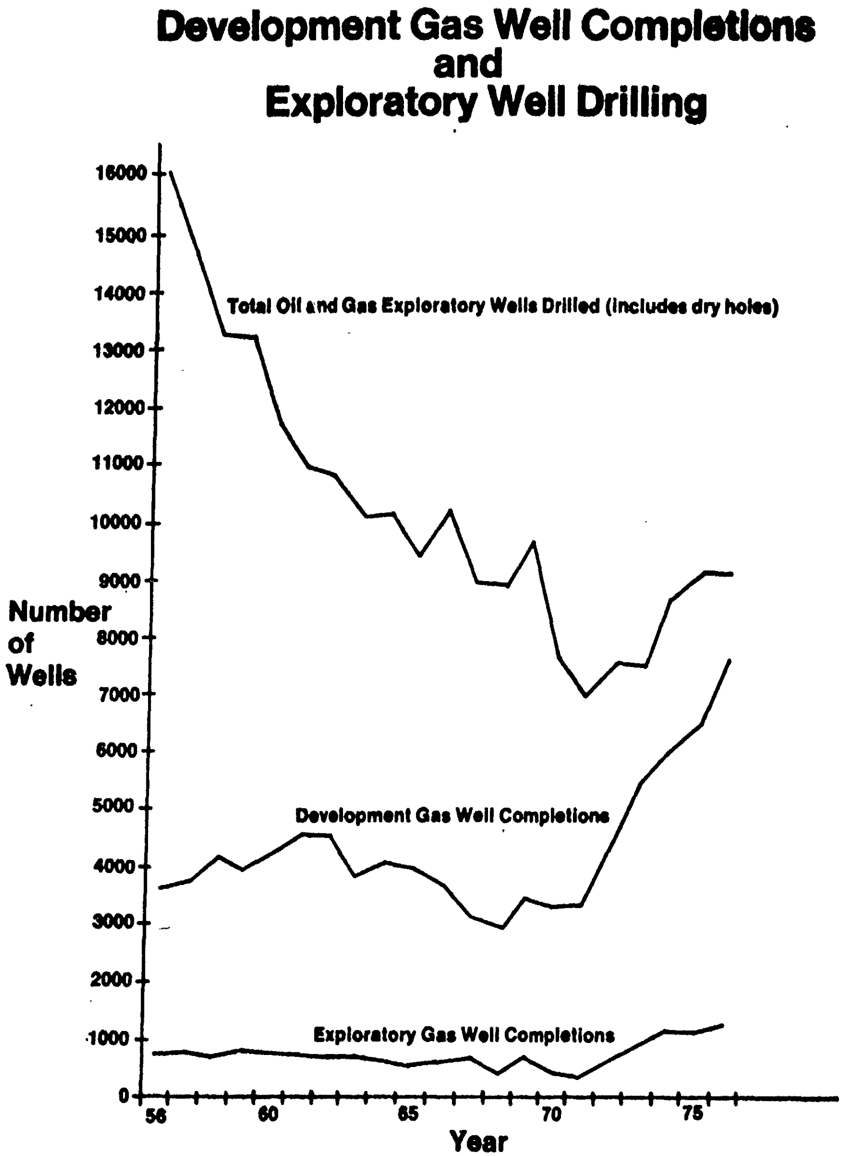
Development Gas Well Completions and Exploratory Well Drilling
16000
15000
14000
13000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Number of Wells
Total Oil and Gas Exploratory Wells Drilled (includes dry holes)
Development Gas Well Completions
Exploratory Gas Well Completions
56
60
65
70
75
Year

CHART 1

Geographic Areas of Potential Gas Estimates.

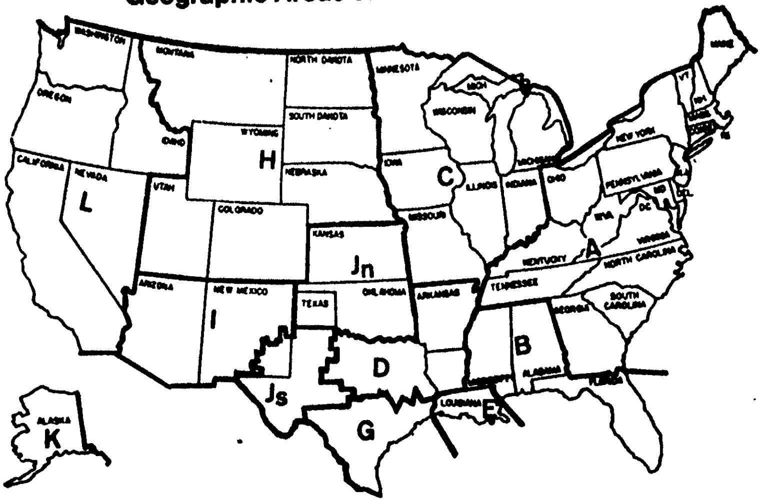

FIGURE 1

E. ANALYSIS OF POTENTIAL GAS ESTIMATES AND DRILLING

Table 1 displays for each of the drilling regions the well completions, reserve additions, production and potential gas resources. In order to compare the gas well completion data, the production estimates, and the potential gas estimates, the gas well completions in each drilling region are expressed as a percentage of total gas well completions in the United States in 1975. Likewise, the potential gas estimates (and production) by drilling region were tabulated as a percent of total U.S. potential (and production). Cost data were expressed in terms of the drilling costs actually experienced in the drilling region in 1975. Units of the cost data are dollars per foot drilled. No allowance was made for the fact that costs are averaged over different drilling depths. It was judged to be more important to reflect the actual drilling expenses for the regions considered.

TABLE 1.—PERCENT

Area	Total Gas well completions	Develop Gas well completions	Exploitation well completions	N.A. additions to proved resources	Production	Total N.A. proved resources	Potential	Cost per foot
A-Shallow	27.07	30.22	8.81	5.79	2.36	2.90	6.61	$21.63
A-Deep	.01						.54	362.11
A-Offshore	0	0	0	0	0	0	3.90	
B-Shallow	.40	.69	3.85	4.41	.50	1.13	1.95	44.36
B-Deep	.29						1.95	82.52
B-Offshore	0	0	0	0	0	0	2.60	
C-Shallow	.75	.51	7.58	.95	.42	.31	.65	42.42
D-Shallow	11.14	11.92	13.26	5.39	5.31	5.29	5.20	31.38
D-Deep	.01						.65	77.25
E-Shallow	2.35	2.61	3.83	6.87	16.23	12.74	1.95	60.33
E-Deep	.39						2.06	120.87
E-Offshore	3.31	2.76	1.64	27.37	21.44	19.08	8.78	[1] 114.96
G-Shallow	14.84	9.86	14.83	9.73	13.49	15.74	4.12	43.98
G-Deep	.08						.98	105.11
G-Offshore	.24	.08	1.76	1.91	1.29	1.90	4.98	151.39
H-Shallow	8.87	9.02	17.93	6.71	2.55	3.80	6.18	35.49
H-Deep	.13						.76	228.09
I_n-Shallow	3.90	5.48	.59	3.50	3.20	4.91	.76	29.76
J_n-Shallow	17.16	18.40	14.75	15.74	19.90	19.67	6.18	36.26
J_n-Deep	.47						5.42	102.27
J_s-Shallow	7.33	7.99	8.32	7.99	11.38	7.44	3.03	36.53
J_s-Deep	.60						3.03	118.14
L-Shallow	.60	.45	2.21	2.31	1.04	1.43	2.49	35.25
L-Deep	.01						.76	131.66
L-Offshore	0	0	0.7	0	0	0	1.08	
K-Onshore	.04	.02	.23	1.32	.85	3.65	24.38	298.33
K-Offshore	0	0	.01	0	0	0		

[1] To $165.45.

Table 2 displays the percent of gas well completions versus the percent of total gas potential ranked in order of the largest ratio of percent gas well completions to percent of potential. As can be seen from the table, the largest percentage of gas well completions is in shallow onshore regions rather than offshore or deep onshore.

Chart 2 is derived from a cumulative plot of the data in Table 2. It shows that more than three quarters of the gas well completions in the United States occurred in areas having only one quarter of the potential gas resource. It shows also that 90 percent of the drilling occurred in areas with less than one third of the estimated national gas potential. This indicates very little drilling in areas with large potential gas resources. If gas well drilling were motivated solely by the potential estimates, this plot would be a straight line at a 45 degree angle. The more this curve tends toward a right angle the more nonoptimum the drilling program is from the viewpoint of exploitation of potential resources. This result indicates that there are factors other than potential resource estimates which srongly influence the region in which gas well drilling has occurred.

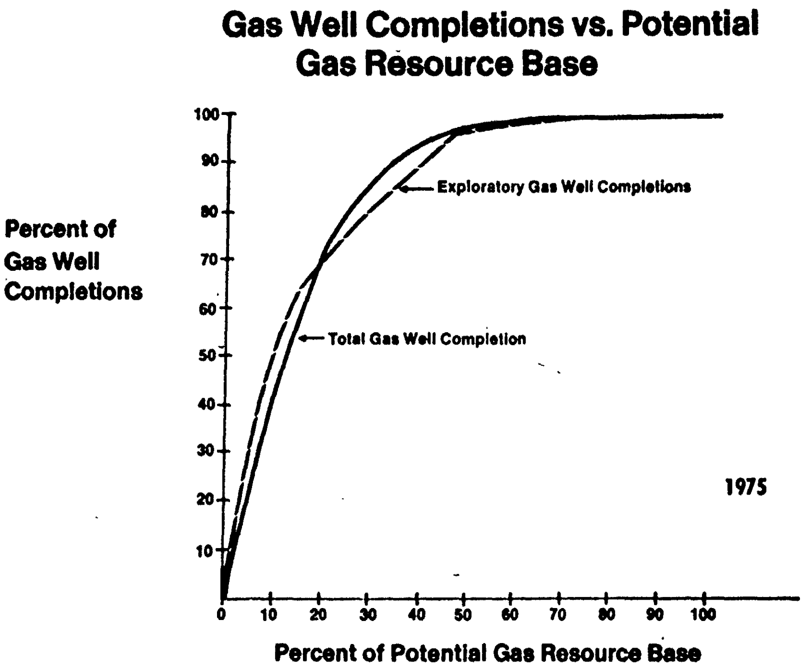

CHART 2

Chart 3 gives some insight into the cost factor.[3] The chart displays the percentage of gas well completions versus the cost of drilling in dollar per foot. This histogram shows the percentage of gas well completions in 1975 which occurred at various drilling costs. It is clear from this histogram that the national drilling effort is heavily biased towards drilling in less expensive areas for which the cost is between $20 and $50 per foot.

[3] Charts 3 and 4 exclude certain regions for which gas well drilling costs are not available. These regions are offshore Atlantic, offshore Florida and offshore California.

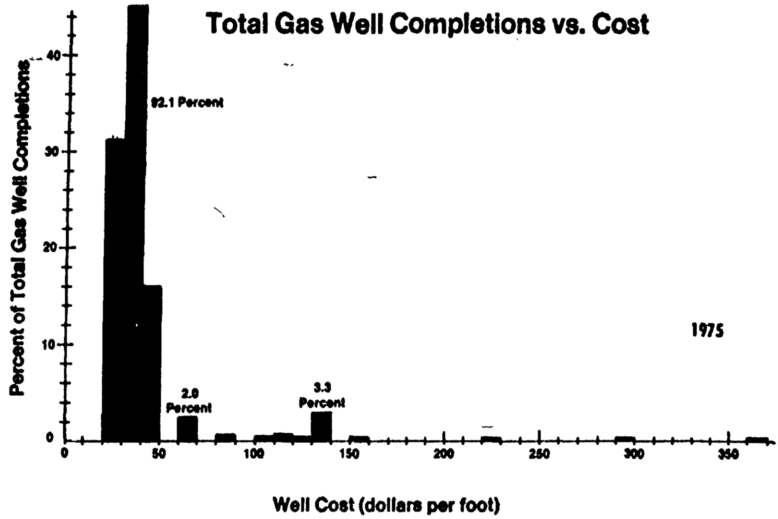

CHART 3

Chart 4 shows the significance of this bias.[2] It portrays the percentage of potential gas against drilling costs as a histogram. It can be seen, based on 1975 drilling data, that much of the potential gas in the United States occurs in regions where the drilling costs in 1975 exceeded $50 per foot. To illustrate this point more fully, only about 40 percent of the national potential occurs in areas for which the drilling costs are less than $100 per foot. Similarly, about 65 percent of the national potential occurs in regions where drilling costs are $160 per foot or less, and more than 90 percent of the national potential occurs in regions for which the drilling cost is less than $300 per foot.

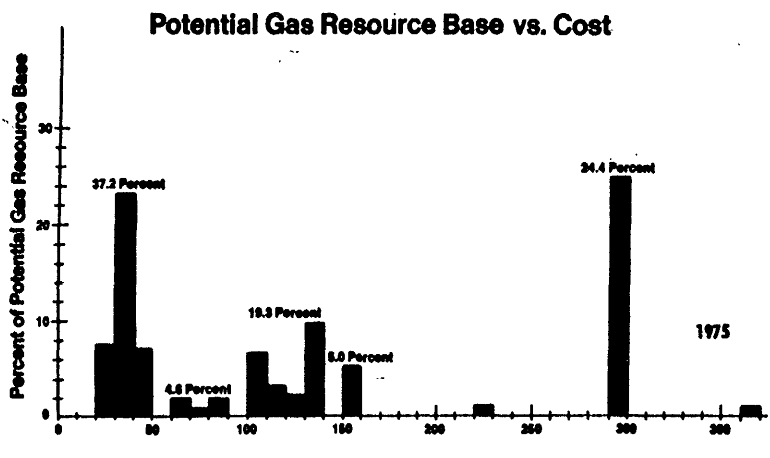

CHART 4

TABLE 2.—DRILLING REGIONS RANKED BY RATIO OF PERCENT GAS WELL COMPLETIONS TO PERCENT POTENTIAL

Area	Gas well Completions	Potential	Success percentage[1]	Drilling cost per foot
I—Shallow[2]	3.90	0.76	85	$29.76
A—Shallow[2]	27.07	6.61	92	21.63
G—Shallow[2]	14.84	4.12	73	43.98
J_a—Shallow[2]	17.16	6.78	60	36.26
J_r—Shallow[2]	7.33	3.03	82	36.53
D—Shallow[2]	11.14	5.20	61	31.38
H—Shallow[2]	8.87	6.18	48	35.49
E—Shallow[2]	2.35	1.95	52	60.33
C—Shallow[2]	.75	.65	45	42.42
E—Offshore	3.31	8.78	62/55	[3] 114.96
L—Shallow[2]	.60	2.49	87	35.25
B—Shallow[2]	.40	1.95	28	44.36
J_r—Deep	.60	3.03	70	118.14
E—Deep	.39	2.06	46	120.87
H—Deep	.13	.76	62	228.09
B—Deep	.29	1.95	34	82.52
J_a—Deep	.47	5.42	60	102.27
G—Deep	.08	.98	43	105.11
G—Offshore	.24	4.98	15	151.39
A—Deep	.01	.54	100	362.11
D—Deep	.01	.65	33	77.25
L—Deep	.01	.76	40	131.66
K	.04	24.38	72	298.83
L—Offshore	0	1.08	93	
B—Offshore	0	2.60		
A-Offshore	0	3.90		

[1] Success percentage is the total number of successful oil and gas wells divided by the number of wells drilled.
[2] Shallow is used here to describe depths of less than 15,000 feet.
[3] To $165.45.

F. DRILLING AND CURRENT PRODUCTION

This analysis indicates that the gas well drilling activity is generally in areas which have been previously explored and are still being developed. Drilling costs in those regions are low. Federal regulators use these drilling costs to set new gas prices. In effect this forces much of the drilling to remain in these mature regions and discourages more expensive frontier development.

This trend is clearly apparent in Chart 5 which depicts cumulative percentages of gas well completions versus percentage of current gas production. These data show that in those regions already producing half of the natural gas over 87% of the new gas wells were completed in 1975. Thus, gas well drilling was largely not aimed at the high potential gas resources areas which have not already been extensively developed.

G. CONCLUSIONS

The results of this analysis indicate that the potential resource of natural gas has not been depleted and is not near depletion. It shows that new drilling regions have not been exploited and still have in place a large percentage of our national gas resource. It also indicates that drilling costs are certain to be higher in these frontier regions. Because federally regulated national gas rates are based on past drilling experience in generally less costly areas, the regulated price has limited higher cost drilling in more risky but potentially more productive areas.

The paradox of large amounts of drilling in the face of dwindling reserves because federal regulation of interstate wellhead gas prices has constrained drilling to regions which are inexpensive and have been extensively explored. Few "giant discoveries" can be expected in these areas and so the statistisc have been mistakenly interpreted to indicate that resource depletion is near. Frontier areas, which are admittedly more expensive drilling regions, contain large volumes of gas which can be developed. Price incentives in the intrastate market have already demonstrated a dramatic turn-around in drilling in the mature, well-developed intrastate areas.

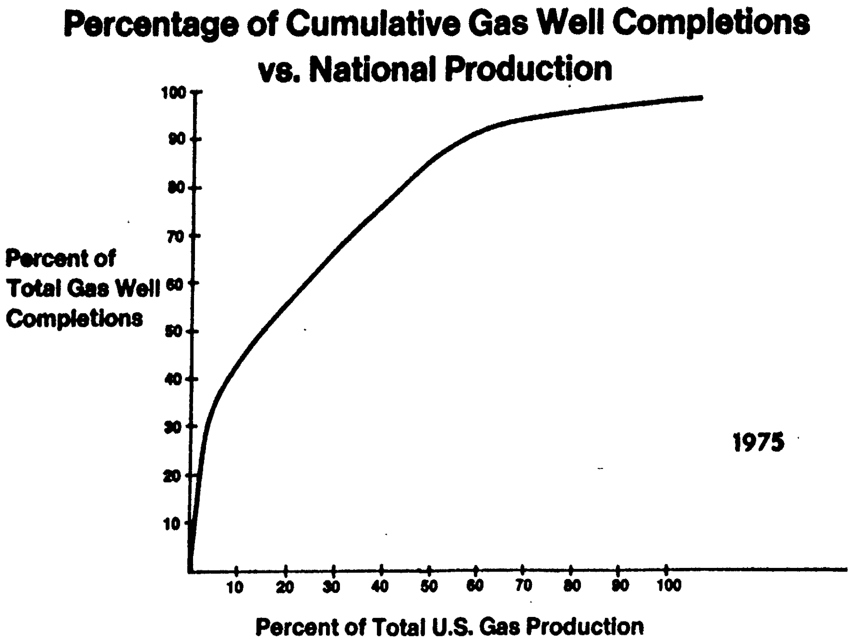

CHART 5

COST TO THE U.S. OF DEREGULATION OF NEW NATURAL GAS PRICES

A. INTRODUCTION

One of the most frequently expressed concerns about deregulation of the wellhead price of new natural gas is the presumed large cost to the country that such a policy could entail. This paper analyzes this issue both from the standpoint of net cost to the country as well as the cost to the residential gas consumer. The key assumptions underlying this analysis are discussed in Appendix A. Because it is uncertain as to what price new natural gas would initially rise as a result of deregulation, three new gas initial average wellhead price scenarios have been analyzed: \$2.25/Mcf, \$2.75/Mcf, and \$3.25/Mcf. \$3.25/Mcf was selected as a maximum case since it is very unlikely that new gas prices would exceed the price of available supplemental gas sources.

B. EXECUTIVE SUMMARY OF RESULTS OF ANALYSIS

Considering the substantial long-term benefits of additional domestic gas production expected from deregulation as compared with continued wellhead price regulation (+3.9 Tcf by 1985 and +5.5 Tcf by 1990), including reduced dependence on foreign oil, the near-term costs of deregulation are small compared to total U.S. energy costs.

The near-term cost of deregulation, even if the average initial new gas price rises as high as \$3.25/Mcf, is estimated in 1978 to be only about \$1 billion (1978 dollars) and in 1980 about \$4 billion (1980 dollars). These costs represent an increase in the country's total gas costs of only 3 percent and 7 percent, respectively, over that expected from continued regulation.

The relatively small cost of deregulation is a result of: (a) the fact that the vast majority of gas produced in the first few years following deregulation is old gas still under regulation at comparatively low prices; and (b) the need to replace the gas which is not produced because of continued regulation by higher cost alternatives such as electricity or No. 2 oil from foreign crude.

The difference between the annual percentage increase in residential gas prices resulting from deregulation and that expected under continued FPC regulation is estimated to be only 11 percent per year through 1980, falling to 7 percent per year through 1985 and 4 percent through 1990, even assuming the highest new gas price scenario ($3.25/Mcf). When the cost of replacement energy paid by residential users who would not have additional gas produced under deregulation is considered, the difference in annual percentage price increases is only 1 percent through 1990.

In the longer term (about 1990), the difference in overall cost to the country between continued regulation and deregulation will vanish because of the large volumes of replacement energy needed as a result of declining gas production from continued regulation.

The overall impact of assumed maximum initial prices of new gas of $2.25/Mcf and $2.75/Mcf are correspondingly smaller than that of the $3.25/Mcf case, but the volumes of additional domestic gas production are also expected to be lower. For example, comparing deregulation ($3.25/Mcf case) with the $2.25/Mcf case results in a difference in gas production of 1.5 Tcf in 1980 with a cost difference of only $2 billion (1980 dollars).

Finally, these approximate cost calculations have not considered three important but less easily quantifiable economic benefits of deregulation: the value of less dependence on foreign imports and therefore less potential economic effects in the event of an oil embargo; the value of full utilization of the present gas transmission and distribution system which, under continued regulation, would go partially unused and would raise the cost of gas to existing customers; and the value of reduced foreign payments for imported energy.

C. PRODUCTION AND NEW RESERVE ADDITIONS

Several recent studies over the past year or so have attempted to estimate the volumes of additional gas that could be obtained from reregulating the price of new natural gas. The results of these studies, including those of the Federal Energy Administration, are shown in Table I. In general, there is reasonably close agreement among these studies that, as a result of deregulation, the decline in gas production can be halted and production can be stabilized at or about 20 Tcf/year until at least the early 1990s. This production is certainly achievable, considering the various estimates[1] of remaining recoverable natural gas resources which range from 600–1300 Tcf.

[1] For example, the USGS potential gas resource estimate is 524–857 Tcf and Industry's Potential Gas Committee's estimate is 923–973 (both are in addition to the estimated proved reserves of 228 Tcf in 1976).

TABLE I.—ADDITIONAL GAS SUPPLIES FROM NEW GAS DEREGULATION LOWER 48 STATES

[In trillions of cubic feet]

	Annual production			
	1976	1980	1985	1990
Continued FPC regulation (770A):[1]				
American Gas Association	19.5	18.1	16.1	14.6
Institute of Gas Technology	19.5	17.4	16.2	(2)
Federal Energy Administration	19.5	16.9	16.6	16.9
MacAvoy/Pindyck	19.5	22.0	(2)	(2)
Deregulation of new gas price:				
American Gas Association[3]	19.5	19.6	20.4	20.0
Institute of Gas Technology[4]	19.5	19.4	21.3	(2)
Federal Energy Administration	19.5	(2)	20.6	(2)
Stanford Research Institute	19.5	23.7	26.4	25.0
MacAvoy/Pindyck	19.5	27.4	(2)	(2)
Percentage increase in volume from deregulation—average of estimates		14.8	26.6	37.7

[1] $1.42/M cu beginning in 1976, plus $0.01 per quarter escalation.
[2] Not available.
[3] Assumes deregulation for all new gas produced after Jan. 1, 1977.
[4] Assumes onshore deregulation in 1976, offshore in 1981.

Assuming, therefore, that the domestic decline in gas production can be halted and production can be stabilized at about 20 Tcf by the early 1980s, Table II shows the corresponding reserve additions and the production of new gas. As seen from Table II, by 1980 about 5.5 Tcf of gas or slightly over 25 percent of all gas would be classified as new and by 1985 about 60 percent or 11.8 Tcf would be new or deregulated gas.

TABLE II.—RESERVES, RESERVE ADDITIONS AND PRODUCTION

[In trillions of cubic feet]

Year	Reserves (yearend) Old	Reserves (yearend) New	Reserve additions (by yearend)	Production (yearend) Old	Production (yearend) New	Production (yearend) Total
1977	177	20	20.2	19.2	0.2	19.4
1978	159	30	21.0	17.4	2.0	19.4
1979	143	56	21.0	15.5	4.0	19.5
1980	129	71	21.0	14.1	5.5	19.6
1985	76	127	20.0	8.2	11.8	20.0
1990	44	157	17.0	4.9	15.2	20.1

D. NEW AND OLD GAS VOLUMES AND PRICES

Table III displays the volumes and prices for each vintage of old, price-regulated gas in the interstate market. While the average price for old interstate gas will remain low, the volumes of this gas are expected to decline rapidly from an estimated 11.3 Tcf in 1977 to 8.2 Tcf in 1980 and to 4.8 Tcf in 1985. This decline is simply a depletion of these vintages.

Tables IV, V, and VI compare the wellhead price and gas volumes for each of the three new gas price scenarios versus continued FPC regulation under Opinion 770A. Volumes and prices are displayed out to 1990 for both old and new gas in the inter- and intrastate markets. Prices in the intrastate market are assumed to be competitive with boiler fuel (No. 6 oil) and are estimated to be $1.97/Mcf in 1977.[2] It should be noted that while new gas prices are considerably higher than old gas prices for all cases, the average price of all gas, even under the $3.25/Mcf new gas price scenario, rises only gradually over time.

TABLE III.—INTERSTATE "VINTAGE" PRODUCTION AND PRICES[1]

Year	Pre-1973 Produced (thousand cubic feet)	Pre-1973 Price (million cubic feet)	1973–74 Produced (thousand cubic feet)	1973–74 Price (million cubic feet)	1975–76 Produced (thousand cubic feet)	1975–76 Price (million cubic feet)	Total Produced (thousand cubic feet)	Total Price (million cubic feet)
1977	10.3	$0.37	0.4	$0.94	0.6	$1.46	11.3	$0.44
1978	9.3	.38	.4	.95	.5	1.50	10.2	.45
1979	8.3	.39	.4	.96	.4	1.54	9.1	.46
1980	7.5	39	.3	.97	.4	1.58	8.2	.47
1981	6.8	.41	.3	.98	.4	1.62	7.5	.49
1982	6.1	.42	.2	.99	.3	1.66	6.6	.49
1983	5.5	.43	.2	1.00	.3	1.70	6.0	.51
1984	4.9	.44	.2	1.01	.3	1.74	5.4	.54
1985	4.4	.45	.2	1.02	.2	1.78	4.8	.53
1986	4.0	.46	.2	1.03	.2	1.82	4.4	.55
1987	3.6	.46	.1	1.04	.2	1.86	3.9	.55
1988	3.2	.48	.1	1.05	.2	1.90	3.5	.58
1989	2.9	.50	.1	1.06	.2	1.94	3.2	.60
1990	2.6	.53	.1	1.07	.2	1.98	2.9	.64

[1] Gas priced in accordance with FPC Opinion 770A. "New" gas initially $1.42 per million cubic feet in 2d quarter of 1976 escalating at $0.01 per quarter thereafter.

[2] The average of new intrastate contracts in the fourth quarter of 1976 was recently reported to be $1.80/Mcf and the average of expiring and renegotiated contracts $1.66/Mcf.

TABLE IV.—IMPACT OF $2.25 NEW GAS PRICE AT THE WELLHEAD

	Production (trillion cubic feet)								Wellhead price (thousand cubic feet)						
	Old gas			New gas		Total gas			Old gas			New gas		Total gas	
	Interstate	Intrastate	Total old	Continued 770A	$2.25 case	Continued 770A	$2.25 case	Additional gas from $2.25 case	Interstate	Intrastate	Total old	Continued 770A	$2.25 case	Continued 770A	$2.25 case
Year:															
1977	11.3	7.9	19.2	0.2	0.2	19.4	19.4		$0.44	$1.97	$1.07	$1.71	$2.25	$1.08	$1.08
1978	10.2	7.2	17.4	1.4	1.4	18.8	18.8		.45	2.25	1.19	2.09	2.48	1.26	1.29
1979	9.1	6.4	15.5	2.8	2.8	18.3	18.3		.46	2.53	1.31	2.31	2.72	1.47	1.53
1980	8.2	5.9	14.1	4.0	4.0	18.1	18.1		.47	2.80	1.45	2.53	2.99	1.69	1.79
1985	4.8	3.4	8.2	7.9	9.1	16.1	17.3	1.2	.53	3.75	1.87	3.18	4.80	2.51	3.41
1990	2.9	2.0	4.9	9.7	13.8	14.6	18.7	4.1	.64	4.79	2.33	3.86	5.44	3.35	4.63

	Production[1] by final market (trillion cubic feet)						Average price[1] by final market (thousand cubic feet)					
	Interstate		Intrastate		Total		Interstate		Intrastate		Total	
	Continued 770A	$2.25 case	Continued 770A	$2.25 case	Continued 770A	$2.25 case	Continued 770A	$2.25 case	Continued 770A	$2.25 case	Continued 770A	$2.25 case
Year:												
1977	11.4	11.4	8.0	8.0	19.4	19.4	$0.45	$0.46	$1.97	$1.97	$1.08	$1.08
1978	10.5	10.7	8.3	8.1	18.8	18.8	.48	.55	2.25	2.27	1.26	1.29
1979	9.7	10.4	8.6	7.9	18.3	18.3	.53	.74	2.53	2.56	1.47	1.53
1980	9.1	10.1	9.0	8.0	18.1	18.1	.58	.95	2.80	2.85	16.9	1.79
1985	7.1	9.6	9.0	7.7	16.1	17.3	.94	2.67	3.75	4.34	2.51	3.41
1990	6.1	11.1	8.5	7.6	14.6	18.7	1.35	4.19	4.79	5.27	3.35	4.63

[1] Old and new gas combined.

TABLE V.—IMPACT OF $2.75 NEW GAS PRICE AT THE WELLHEAD

	Production (trillion cubic feet)								Wellhead price (thousand cubic feet)						
	Old gas			New gas		Total gas		Additional gas from $2.75 case	Old gas			New gas		Total gas	
	Interstate	Intrastate	Total old	Continued 770A	$2.75 case	Continued 770A	$2.75 case		Interstate	Intrastate	Average old	Continued 770A	$2.75 case	Continued 770A	$2.75 case
Year:															
1977	11.3	7.9	19.2	0.2	0.2	19.4	19.4	----------	$0.44	$1.97	$1.07	$1.71	$2.75	$1.08	$1.09
1978	10.2	7.2	17.4	1.4	1.7	18.8	19.1	0.3	.45	2.25	1.19	2.09	2.80	1.26	1.34
1979	9.1	6.4	15.5	2.8	3.4	18.3	18.9	.6	.46	2.53	1.31	2.31	3.23	1.47	1.66
1980	8.2	5.9	14.1	4.0	4.8	18.1	18.9	.8	.47	2.80	1.45	2.53	3.49	1.69	1.97
1985	4.8	3.4	8.2	7.9	10.8	16.1	19.0	2.9	.53	3.75	1.87	3.18	4.80	2.51	3.53
1990	2.9	2.0	4.9	9.7	15.2	14.6	20.1	5.5	.64	4.79	2.33	3.86	5.37	3.35	4.63

	Production[1] by final market (trillion cubic feet)						Average price[1] by final market (thousand cubic feet)					
	Interstate		Intrastate		Total		Interstate		Intrastate		Total	
	Continued 770A	$2.75 case	Continued 770A	$2.75 case	Continued 770A	$2.75 case	Continued 770A	$2.75 case	Continued 770A	$2.75 case	Continued 770A	$2.75 case
Year:												
1977	11.4	11.4	8.0	8.0	19.4	19.4	$0.45	$0.46	$1.97	$1.98	$1.08	$1.09
1978	10.5	11.0	8.3	8.1	18.8	19.1	.48	.62	2.25	2.31	1.26	1.34
1979	9.7	11.0	8.6	7.9	18.3	18.9	.53	.94	2.53	2.66	1.47	1.66
1980	9.1	10.9	9.0	8.0	18.1	18.9	.58	1.22	2.80	2.98	1.69	1.97
1985	7.1	11.3	9.0	7.7	16.1	19.0	.94	2.99	3.75	4.34	2.51	3.63
1990	6.1	12.5	8.5	7.6	14.6	20.1	1.35	4.27	4.79	5.21	3.35	4.63

[1] Old and new gas combined.

TABLE VI.—IMPACT OF $3.25 NEW GAS PRICE AT THE WELLHEAD

	Production (trillion cubic feet)								Wellhead price (thousand cubic feet)						
	Old gas			New gas		Total gas		Additional gas from $3.25 case	Old gas			New gas		Total gas	
	Inter-state	Intra-state	Total old	Continued 770A	$3.25 case	Continued 770A	$3.25 case		Inter-state	Intra-state	Total old	Continued 770A	$3.25 case	Continued 770A	$3.25 case
Year:															
1977	11.3	7.9	19.2	0.2	0.2	19.4	19.4	----------	$0.44	$1.97	$1.07	$1.71	$3.25	$1.08	$1.09
1978	10.2	7.2	17.4	1.4	2.0	18.8	19.4	0.6	.45	2.25	1.19	2.09	3.44	1.26	1.43
1979	9.1	6.4	15.5	2.8	4.0	18.3	19.5	1.2	.46	2.53	1.31	2.31	3.63	1.47	1.79
1980	8.2	5.9	14.1	4.0	5.5	18.1	19.6	1.5	.47	2.80	1.45	2.53	3.84	1.69	2.12
1985	4.8	3.4	8.2	7.9	11.8	16.1	20.0	3.9	.53	3.75	1.87	3.18	4.80	2.51	3.60
1990	2.9	2.0	4.9	9.7	15.2	14.6	20.1	5.5	.64	4.79	2.33	3.86	5.37	3.35	4.63

	Production[1] by final market (trillion cubic feet)						Average price[1] by final market (thousand cubic feet)					
	Interstate		Intrastate		Total		Interstate		Intrastate		Total	
	Continued 770A	$3.25 case	Continued 770A	$3.25 case	Continued 770A	$3.25 case	Continued 770A	$3.25 case	Continued 770A	$3.25 case	Continued 770A	$3.25 case
Year:												
1977	11.4	11.4	8.0	8.0	19.4	19.4	$0.45	$0.47	$1.97	$1.99	$1.08	$1.09
1978	10.5	11.3	8.3	8.1	18.8	19.4	.48	.74	2.25	2.38	1.26	1.43
1979	9.7	11.6	8.6	7.9	18.3	19.5	.53	1.15	2.53	2.74	1.47	1.79
1980	9.1	11.6	9.0	8.0	18.1	19.6	.58	1.46	2.80	3.08	1.69	2.12
1985	7.1	12.3	9.0	7.7	16.1	20.0	.94	3.13	3.75	4.34	2.51	3.60
1990	6.1	12.5	8.5	7.6	14.6	20.1	1.35	4.27	4.79	5.21	3.35	4.63

[1] Old and new gas combined.

E. TOTAL WELLHEAD GAS COSTS

Table VII compares the estimated total wellhead cost of gas through 1990 for each of the three new gas price scenarios and for continued regulation under 770A. While total cost of gas from the $3.25/Mcf new gas price scenario is the highest of all the cases, this is due in part to the larger gas volumes expected from this scenario.

F. TOTAL GAS DELIVERY COSTS

Table VIII displays the aggregate gas delivery cost for each of the new gas price scenarios and for continued regulation, i.e. 770A. The average unit delivery cost ($1.11/Mcf) to all users in 1977 is expected to approximately equal the average wellhead cost and is assumed to increase with inflation (at 5%) thereafter.

G. REPLACEMENT ENERGY COSTS

Table IX displays the results of the calculation of the cost of alternative forms of energy that would be needed in the absence of new gas price deregulation resulting in maximum new gas production. The replacement volumes of gas in the table are the estimated difference in volumes from deregulation. Replacement costs were calculated assuming the replacement of half the gas deficit with electricity for residences and half with No. 2 oil for industry or commercial use.[3] Since the least volumes of new gas are produced under the 770A case, the maximum replacement volumes are needed resulting in the case with the highest cost of replacement fuel.

H. TOTAL COST TO THE COUNTRY OF DEREGULATION

Tables X, XI and XII display, respectively, the aggregate cost to the country from each new gas price scenario considering, as appropriate, the need for replacement energy.

The detailed results of the analyses are:

TABLE VII.—WELLHEAD COSTS CALCULATION[1]

Year	Gas volumes (trillions of cubic feet)				Total cost (dollars in billions)			
	770A	$2.25	$2.75	$3.25	770A	$2.25	$2.75	$3.25
1977	17.1	17.1	17.1	17.1	18.5	18.6	18.6	18.8
1978	16.5	16.5	16.8	17.1	21.0	21.3	22.7	24.3
1979	16.0	16.0	16.6	17.2	23.5	24.5	27.6	30.8
1980	15.8	15.8	16.4	17.3	26.3	28.3	32.3	36.7
1985	13.8	15.8	16.7	17.7	34.2	55.0	59.3	64.3
1990	12.3	16.3	17.8	17.8	41.1	75.6	83.6	82.6

[1] Total wellhead costs are computed only for gas delivered to end users. In 1977, this is estimated to be approximately 2.3 T ft³ less than production of 19.4 T ft³.

TABLE VIII.—GAS DELIVERY COST CALCULATION[1]

Year	Gas volumes				Average unit delivery cost (dollars M ft³)[2]	Total delivery costs (dollars in billions)			
	770A	$2.25	$2.75	$3.25		770A	$2.25	$2.75	$3.25
1977	1.46	14.6	14.6	14.6	1.11	16.2	16.2	16.2	1 6.2
1978	14.0	14.0	14.3	14.3	1.17	16.4	16.4	16.7	17.1
1979	13.5	1.35	14.1	14.7	1.23	16.6	16.6	17.3	18.1
1980	1.33	13.3	13.9	14.8	1.29	17.2	17.2	17.9	19.1
1985	11.3	13.3	14.2	15.2	1.65	18.6	31.9	23.4	25.1
1990	9.8	13.8	15.3	15.3	2.11	20.7	29.1	32.3	32.3

[1] Delivery cost includes only utility sales. Delivery cost of remaining 2.5 T ft³ of direct sales by producers is approximately $1,000,000,000.

[2] Based on 5-percent escalation per year of 1976 average transmission and distribution cost of $1.06 M ft³ to all utility customers.

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[3] The implication of this assumption is that half of the additional gas as a result of new gas price deregulation would go to residences or commercial users that otherwise would be forced to electricity at a higher price. In 1976, almost half of all gas was used in the residential and commercial market.

TABLE IX.—REPLACEMENT ENERGY CALCULATION

Year	Unit cost of replacement energy (dollars per MMBtu) No. 2 oil [1]	Unit cost of replacement energy (dollars per MMBtu) Electricity [2]	Replacement volumes (T ft [3]) 770-A	$2.25	$2.75	$3.25	Total cost of replacement energy (billions of dollars) [3] 770-A	$2.25	$2.75
1977	3.28	6.51							
1978	3.44	6.84	0.6	0.6	0.3		3.1	3.1	1.5
1979	3.61	7.17	1.2	1.2	.6		6.5	6.5	3.2
1980	3.79	7.53	1.5	1.5	.7		8.5	8.5	4.0
1985	4.84	9.61	3.9	2.7	1.0		28.2	19.5	7.2
1990	6.18	12.28	5.5	1.5	0		50.8	13.8	0

[1] No. 2 oil refined from foreign crude oil: 1976 delivered price is $3.12 per MMBtu.
[2] Electricity cost based on use of electric heat pump (COP of 2.3) for 60 percent of residential use; remaining 40 percent assumes standard efficiencies for hot water heating and appliances. 1976 average is $6.20 per MMBtu.
[3] Replacement energy assumed to be ½ residential electricity and ½ No. 2 oil.

TABLE X.—COST TO THE COUNTRY OF $2.25/MCF INITIAL NEW GAS PRICE SCENARIO [1]

[Current year dollars] [2]

Year	Additional domestic gas from $2.25 price (T ft [3]) [3]	Average wellhead price (dollars per M ft [3]) 770-A	Initial $2.25	Total wellhead and delivery costs (billions of dollars) 770-A plus replacement energy [4]	Initial $2.25 plus replacement energy [4]	Percentage difference in cost of energy to United States
1977	0	1.08	1.09	35	35	0
1978	0	1.27	1.29	40	40	0
1979	0	1.47	1.53	46	47	2
1980	.1	1.66	1.79	52	54	4
1985	2.0	2.48	3.48	81	97	20
1990	4.0	3.34	4.64	113	118	4

[1] $2.25 per M ft [3] initial price approximately equal, on a delivered basis, to an average of No. 2 and No. 6 oil refined from foreign crude. $2.25 initial new gas price assumed to escalate at a rate sufficient to bring average price of all gas by 1985 to equivalent of No. 2 oil refined from world oil.
[2] Escalation of 5 percent annually assumed for world oil prices and domestic gas delivery costs.
[3] Volumes of additional onshore gas from $2.25 initial new gas price are assumed to be negligible until after 1980 since this price is only slightly higher than current intrastate market prices.
[4] Replacement energy assumed to be half residential electric assuming heating and cooling with an electric heat pump and half No. 2 fuel oil refined from foreign crude.
[5] Replacement energy costs account for additional gas that would be produced under $3.25 deregulation scenario.

TABLE XI.—COST TO THE COUNTRY OF $2.75 PER M FT [3] INITIAL NEW GAS PRICE SCENARIO [1]

[Current year dollars] [2]

Year	Additional domestic gas from $2.75 price (T ft [3]) [3]	Average wellhead price (dollars per M ft [3]) 770-A	Initial $2.75	Total wellhead and delivery costs (billions of dollars) 770-A plus replacement energy [3]	Initial $2.75 plus replacement energy [4]	Percentage difference in cost of energy to United States
1977	0	1.08	1.09	35	35	0
1978	.3	1.27	1.35	40	41	2
1979	.6	1.47	1.66	46	48	4
1980	.8	1.66	1.97	52	54	4
1985	2.9	2.48	3.55	81	90	11
1990	5.5	3.34	4.64	113	115	2

[1] $2.75 per M ft [3] initial price approximately equal, on a delivered basis, to No. 2 oil refined from foreign crude. $2.75 initial new gas price assumed to escalate at a rate sufficient to bring average price of all gas by 1985 to equivalent of No. 2 oil refined from world oil.
[2] Escalation of 5 percent annually assumed for world oil price and domestic gas delivery cost.
[3] Replacement energy assumed to be half residential electric assuming heating and cooling with an electric heat pump and half No. 2 fuel oil refined from foreign crude.
[4] Replacement energy costs account for additional gas that would be produced under $3.25 deregulation scenario.

TABLE XII.—COST TO THE COUNTRY OF $3.25 PER MILLION CUBIC FEET INITIAL NEW GAS PRICE SCENARIO [1]

[Current year dollars] [2]

Year	Additional domestic gas from $2.25 price (T ft³) [3]	Average wellhead price (dollars per M ft³) 770–A	Average wellhead price (dollars per M ft³) Initial $3.25	Total wellhead and delivery costs dollars in (billions) 770–A plus replacement energy [4]	Total wellhead and delivery costs dollars in (billions) Initial $3.25	Percentage difference in cost of energy to United States
1977	0	1.08	1.10	35	35	0
1978	0.6	1.27	1.42	40	41	3
1979	1.2	1.47	1.79	46	49	6
1980	1.5	1.66	2.12	52	56	8
1985	3.9	2.48	3.63	81	89	10
1990	5.5	3.34	4.64	113	115	2

[1] $3.25 per million cubic foot initial price approximately equal to most recent LNG prices delivered to pipeline.
[2] Escalation of 5 percent annually assumed for world oil price and domestic gas costs.
[3] Volumes of additional gas above continued regulation (i.e. 770A) are consistent with increases from deregulation estimated by FEA, IGT, and A.G.A.
[4] Replacement energy assumed to be half residential electric assuming heating and cooling with an electric heat pump and half No. 2 fuel oil refined from foreign crude.

1. The net economic cost to the U.S. as a result of deregulation of the wellhead price of new natural gas, even assuming new gas prices rise to $3.25/Mcf, is estimated to be only $2 billion in the first year (1978) and rising to $4 billion in 1980. This increase is only a small fraction of the $25 billion annual increased costs of foreign oil following the Arab Oil Embargo of 1973–74.

2. When both average wellhead and delivery costs are considered, the additional costs of new gas deregulation represent only a 3 percent average increase in the total cost of energy to all gas consumers in 1978 and an 8 percent increase in 1980 over that which is expected to result from continued FPC wellhead price regulation (i.e. 770A).

Because of the ability of the interstate pipelines to roll-in the small volumes of higher priced new gas in the first few years following deregulation, the wellhead price of new natural gas committed to the interstate market may rise temporarily above the Btu equivalent price of alternative energy sources.

For example, in 1980 the total delivered cost of deregulated gas is estimated to be, at most, $56 billion; $37 billion in wellhead gas costs and $19 billion for transmission and distribution costs. With continued FPC regulation, the total delivered cost of the gas plus oil and electricity required to replace the additional gas that otherwise would have been produced from deregulation of new gas is estimated at $52 billion. Thus, the total difference in cost to the gas customer is about $4 billion—the difference between $56 billion cost under deregulation and $52 billion under continued FPC regulation.

While the average wellhead price of new natural gas under deregulation may rise temporarily above the Btu equivalent of alternatives, the average wellhead price of all gas (old and new) under deregulation would increase only gradually, rising to an estimated $2.12/Mcf in 1980 compared to the $1.66/Mcf under continued FPC wellhead price regulation. This gradual increase results from the predominant volumes of low-priced old gas in the early years following deregulation.

3. In the far term, the difference in cost of the country between deregulation of new gas prices (even assuming the $3.25/Mcf new gas price scenario) and continued regulation vanishes completely as greater volumes of costly replacement energy are needed. By 1990, about 5.5 Tcf of replacement energy is needed, reducing the total difference between deregulation and continued regulation to about $2 billion (1990 dollars) out of a total energy cost of $113 billion (1990 dollars).

4. The net increased costs to the consumer resulting from assumed new gas prices of $2.25/Mcf or $2.75/Mcf (escalated) are smaller than the $3.25/Mcf case, but the volumes of new gas are also expected to be lower. In the first year (1978), the increases in total cost to the consumer above the cost of 770A for these price scenarios are $0 billion and $1 billion, respectively. The estimated increase in 1980 is $2 billion for both cases.

If the wellhead price of new natural gas is $2.75/Mcf (i.e. approximately equivalent on a Btu basis to No. 2 fuel oil refined from foreign crude oil), then the net economic cost to the country is estimated to be approximately $1 billion the first year (1978), rising to $2 billion per year in 1980. This amounts to approximately a 2 percent increase in the cost of energy to the gas consumer in the first year and 4 percent in 1980 over that which is expected to result from continued FPC wellhead regulation of gas prices and the cost of additional imported oil and electricity needed to offset reduced gas production.

If the wellhead price of new natural gas is limited to $2.25/Mcf (i.e. approximately equivalent on a Btu basis to the average of No. 2 and No. 6 oil refined from foreign crude oil), then the net economic cost to the country is estimated to be $0 billion in the first year (1978), rising to $2 billion in 1980. This amounts to approximately a 4 percent increase in the cost of energy in 1980 to the gas consumer over that which is expected to result from continued FPC wellhead regulation of gas prices and the cost of additional imported oil and electricity needed to offset reduced gas production.

5. Finally, it should be emphasized that the calculations underlying this analysis have not credited any economic benefit to deregulation as a result of the increased volumes of domestic gas production resulting in:

Lower imports of energy and consequent reduction in potential cost of economic disruption from an embargo.

Higher utilization (therefore lower unit consumer costs) of the existing gas pipeline and distribution system.

Reduced foreign payments for energy.

I. Impact of deregulation on the residential user

Table XIII displays the impact of deregulation, for each of the initial new gas price scenarios, on the residential gas consumer. In general, the impact on the residential consumer is only slightly higher than the impact of deregulation on all gas users, i.e. including large commercial and industrial users.

Under continued regulation, the volumes of gas available for the residential market have been assumed to remain constant over time while the volumes of total gas produced in the U.S. are projected to decline to about 18 Tcf in 1980, 16 Tcf in 1985, and 14.5 Tcf in 1990. Thus, in this analysis it was assumed that the declining supplies of gas under continued regulation would not impact existing residential consumers.

Under deregulation, however, the overall production of gas is estimated to remain approximately constant at about 20 Tcf, at least until the early 1990s. It has been assumed that approximately one-half of the additionall volume of gas resulting from deregulation (that would not have been produced under continued regulation) would be available for the residential and commercial markets. Thus, conversely, residential and commercial users that otherwise would have been supplied with the additional gas from deregulation would have to resort generally to electricity as a replacement.

Table XIII shows the percent difference that would be paid by the average residential gas user under continued regulation and under each of the new gas price scenarios. The percentages displayed in the table refer to the increased cost to current residential consumers, i.e. those consumers that would have gas under continued regulation or under deregulation.

The percentages shown on Table XIV average in the effect of those new residential and commercial customers who, without additional gas from deregulation, would be forced to much higher priced electricity. Thus, for the same overall amount of energy produced from gas under deregulation, the percentages in the table reflect the impact on the average gas user for equivalent amounts of usable energy.

The results indicate that the average annual increase in the cost of a unit of energy to the current residential gas consumer under deregulation (even assuming the $3.25/Mcf new gas price scenario) is only 16 percent per year in 1978, falling to 13 percent per year by 1985 and 10 percent per year in 1990. Under continued regulation (i.e. FPC Opinion 770A), the percentage increase in 1978 would be 5 percent and would rise to 6 percent per year by 1985 and remain at this annual rate through 1990.

Thus, the difference in percentage annual growth rate between continued regulation and deregulation (assuming the highest new gas price scenario, $3.25/Mcf) is only 11 percent per year through 1980 and falls to 7 percent per year in 1985 and 4 percent per year in 1990.

Table XIV displays the average price of energy to both new and old residential users considering the higher energy cost paid by new residential customers who would not have the additional gas produced under deregulation. Thus, when the cost of replacement energy is considered, the annual percentage increase in residential prices under 770A rises considerably and the difference in annual percentage increase between all deregulation price scenarios and continued regulation is only about 3 percent per year.

It should be emphasized that all costs and prices in this analysis except wellhead prices under continued regulation (FPC Opinion 770A) reflect estimated inflation of 5 percent annually. Thus, at least half the growth in costs to the Nation and residential prices under the three initial "new" gas price cases is attributable to inflation.

TABLE XIII.—IMPACT OF DEREGULATION ON RESIDENTIAL PRICES—CURRENT USERS

[Dollars escalated at 5 percent per year]

Year	Average residential price—current users (dollars per M ft³)[1]				Annual percentage increase in price[2]				Difference in annual percentage increase from 770A		
	770A	$2.25	$2.75	$3.25	770A	$2.25	$2.75	$3.25	$2.25	$2.75	$3.25
1977	2.13	2.14	2.14	2.15							
1978	2.24	2.31	2.38	2.50	5	8	11	16	3	6	11
1979	2.38	2.49	2.69	3.00	6	8	12	18	2	6	12
1980	2.52	2.89	3.16	3.40	6	10	14	17	4	8	11
1985	3.42	5.15	5.47	5.61	6	12	12	13	6	6	7
1990	4.52	7.36	7.44	7.44	6	10	10	10	4	4	4

[1] Transmission and distribution costs to residential users based on $1.60 per M ft³ escalated at 5 percent annually. See tables IV, V, and VI for wellhead prices.

[2] Annual percent growth rate from base year (1977).

TABLE XIV.—IMPACT OF DEREGULATION ON RESIDENTIAL PRICES

[Dollars escalated at 5 percent per year]

Year	Average composite residential price[1] (dollars per M ft³)				Annual percentage increase in price[2]				Difference in annual percentage increase from 770A		
	770A plus replacement	$2.25 plus replacement	$2.75 plus replacement	$3.25 plus replacement	770A	$2.25	$2.75	$3.25	$2.25	$2.75	$3.25
1977	2.13	2.14	2.14	2.15							
1978	2.42	2.48	2.48	2.50	14	16	16	16	2	2	2
1979	2.74	2.83	2.85	3.00	13	15	15	18	3	3	5
1980	2.99	3.30	3.35	3.40	12	16	16	17	4	4	5
1985	4.71	5.60	5.69	5.61	10	13	13	13	3	3	3
1990	6.62	7.72	7.44	7.44	9	10	10	10	1	1	1

[1] Composite price is a volume-weighted average of the price of gas paid by current users and the price of higher cost electricity paid by new users who would have had gas under deregulation.

[2] Annual percent increase from base year (1977).

APPENDIX A

KEY ASSUMPTIONS

General

World oil prices will escalate at 5-percent annually starting at $13.50 per barrel in 1976.

A 5-percent escalation rate will also apply to oil refining and to gas transmission and distribution costs.

Continued FPC regulation under 770A

Future interstate gas prices would be regulated in conformance with FPC Opinion 770A.

Future intrastate gas prices would be set by the market and are assumed to be equivalent in dollars per million Btu to the cost of No. 6 residual fuel refined from foreign crude and sold to industrial consumers in the West South Central Region.

Future new gas dedications to the interstate market would be limited to offshore supplies.

Total gas volumes as a result of continued regulation will decline to 18 Tcf in 1980 and 16 Tcf in 1985 (as estimated by FEA, IGT, and A.G.A.).

Deregulation of new gas

Deregulation would affect only gas sold for the first time after January 1, 1977. Expiring intrastate contracts would not qualify as new gas in the interstate market.

An orderly transition to deregulation will be accomplished by assuming a maximum price of $3.25/Mcf for new gas—a level commensurate with the latest new LNG proposals—escalating at about 5-percent annually until 1984.

Higher new gas prices will generate sufficient reserve additions to raise total production to 20 Tcf, and maintain it at that level through 1990 as estimated by FEA, IGT, and A.G.A.

From 1985 onwards, market forces would set the price of all new gas, regardles of whether sold interstate or intrastate.

The unregulated new gas wellhead price would be such that, after adding transmission and distribution costs, the rolled-in average price of gas to industrial users in the East North Central would be at parity per million Btu with the cost of No. 2 distillate fuel refined from world oil.

Old interstate gas (i.e. pre 1977) would continue to be regulated by the FPC at prices established for those vintages.

The prices for old intrastate gas would not be triggered to new gas prices but would continue to flow intrastate at prices which create parity with No. 6 residual fuel for industrial usage sold in West South Central Region refined from world oil.

A Comparison of Estimates of Additional Natural Gas Production From Deregulation of New Gas Prices

Introduction

One of the principal implied assumptions in the President's National Energy Plan (NEP) is that domestic natural gas production is in a permanent state of decline and that additional significant supplies of gas cannot be produced at prices competitive with alternative energy sources. There are, however, several independent studies conducted both in the public and private sectors which suggest that in a deregulated free market, lower 48 state natural gas production could continue to provide substantial quantities of domestic energy at level approximating current production through 1990.

This paper compares four analyses of natural gas production under current Federal Power Commission (FPC) regulation and under a policy of deregulation of wellhead prices of new natural gas. The sources of these studies are: Massachusetts Institute of Technology (MIT, American Gas Association (A.G.A.), Federal Energy Administration (FEA), and the Institute of Gas Technology (IGT).

Executive Summary

A comparison of these studies indicates that with deregulation of new gas wellhead prices, production of domestic natural gas would be substantially higher than under continued regulation and could be maintained at about current levels through 1985. These studies indicate that:

Continued regulation will result in significantly lower production in 1985 (i.e. 3–4 Tcf lower) than would occur with deregulation of new gas wellhead prices.

Wellhead prices for new gas under deregulation are estimated in the various studies to range between $2.00 to $2.90/Mcf (1975 dollars) in 1985.

Deregulation Analyses

Four studies have recently been conducted on the effects of deregulation of new gas wellhead prices.

A study by the Massachusetts Institute of Technology, partially funded by the National Science Foundation, on world energy futures entitled: "Energy: Global Prospects 1985–2000.[1]

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[1] Wilson, Carroll L., Project Director, *Energy: Global Prospects 1985–2000*, Report of the Workshop on Alternative Energy Strategies, McGraw-Hill Book Company, New York, 1977, pages 153–154.

An American Gas Association analysis of the national costs of deregulation of new gas wellhead prices entitled: "Cost to the U.S. of Deregulation of New Natural Gas Prices." [2]

An analysis by the Institute of Gas Technology entitled: "Projections of New Gas Supplies and Energy Costs Under Three Regulatory Policies." [3]

An analysis of deregulation of new gas wellhead prices compared with continued regulation by the Federal Energy Administration.[4]

PRICES

Continued regulation

In each analysis, continued regulation is predicated on FPC Opinion 770A, which sets the wellhead price of interstate natural gas at $1.42 per thousand cubic feet (Mcf) in the third quarter of 1976 ($1.33/Mcf in constant 1975 dollars). This new gas price may rise thereafter by $0.01/Mcf per quarter.

Deregulation

Although price assumptions vary slightly in each analysis, primarily depending on the form of deregulation, (i.e. phased, new inter and intrastate gas only, treatment of old gas under expired contracts, etc.), price estimates for new wellhead gas, for the most part, fall within a relatively narow range, from $2.00 to $2.90/Mcf (see Table 1).

TABLE 1.—*1985 new gas prices under deregulation (1975 dollars)*

	dollars per thousand cubic feet
Massachusetts Institute of Technology	[1] 1.98
American Gas Association	[2] 2.90
Institute of Gas Technology	[3] 2.50
Federal Energy Administration	[4] 2.40

[1] Assumes Btu parity with world oil in 1975 ($11.50/Bbl).
[2] Assumes new gas price in the range of $2.75 to $3.25 in 1977 dollars. Long-term parity price is estimated to be $2.67 in 1975 dollars and is reached by 1990.
[3] Based on $2.63/Mcf in 1976 dollars.
[4] Calculated from published data. Assumes old regulated interstate price of $0.53/Mcf and volume of 3.8 Tcf, 15.8 Tcf of unregulated new gas, and FEA published average wellhead price of $1.91/Mcf in 1975 dollars (page V–120).

These estimated new gas prices compare closely with the current price proposed for new crude oil under the National Energy Plan. By 1985, the Plan proposes that new oil will be priced at an estimated $13.24/Bbl (1975 dollars). On a Btu parity basis, this equates with a new gas wellhead price of approximately $2.30/Mcf (1975 dollars).

For new gas wellhead prices, on the other hand, it is estimated that the price will be $3.01 in 1985. In constant 1975 dollars, this is approximately equivalent to $1.84/Mcf significantly below the Plan's new oil equivalent price of $2.35/Mcf (1975 dollars) and also well below the estimates of deregulated new gas prices used in these analyses.

GAS PRODUCTION

There is good agreement among the results of the four studies (see Table 2). Continued FPC regulation (Opinion 770A) results in a production volume of about 16 Tcf/year in 1985 in each of the studies. Deregulation of new gas wellhead prices results in estimated production volumes between 19.1 and 21.6 Tcf/year in 1985. The lower estimate for deregulation (MIT study) can be attributed to the lower deregulated price ($1.98/Mcf) assumed by MIT.

If one compares the differences between production under continued regulation and deregulation for each study, there is an even greater degree of agreement (see Table 3). Between 3.0 and 5.4 Tcf of additional production is estimated to occur as a result of deregulation. In three of the four studies, the production of natural gas under deregulation is expected to exceed current levels, in one case more than 1 Tcf/year.

[2] American Gas Association. *Cost to the U.S. of Deregulation of New Natural Gas Prices*, Arlington, Virginia, April 1977.
[3] Institute of Gas Technology, *Projections of New Gas Supplies and Energy Costs Under Three Regulatory Policies*, "Energy Topics." Chicago, Illinois, March 1977.
[4] Federal Energy Administration, *Draft National Energy Outlook 1977*, Washington, D.C., January 1977, Section V.

TABLE 2.—DOMESTIC NATURAL GAS PRODUCTION FORECASTS

[In trillions of cubic feet]

Source	1976 actual	1985 forecast	1990 forecast	2000 forecast
Massachusetts Institute of Technology:				
Deregulation	19.5	19.1	(1)	15.2
Continued regulation	19.5	16.1	(1)	11.4
American Gas Association:				
Deregulation	19.5	20.0	20.1	17.4
Continued regulation	19.5	16.1	14.6	11.6
Institute of Gas Technology:				
Deregulation	19.5	21.6	(1)	(1)
Continued regulation	19.5	16.2	(1)	(1)
Federal Energy Administration:				
Deregulation	19.5	20.6	(1)	(1)
Continued regulation	19.5	16.3	(1)	(1)

[1] Not available.

TABLE 3.—ADDITIONAL ANNUAL PRODUCTION FROM DEREGULATION [1]

[In trillion cubic feet]

Source	1985	1990	2000
Massachusetts Institutes of Technology	3.0	(2)	3.8
American Gas Association	3.9	5.5	5.8
Institute of Gas Technology	5.4	(2)	(2)
Federal Energy Administration	4.3	(2)	(2)

[1] Calculated by subtracting continued regulation forecast from deregulation forecast.
[2] Not available.

A Comparison of Coil Use for Gasification Versus Electrification

INTRODUCTION

As a result of the increasing reliance by the U.S. on foreign energy sources in the past few years, there is considerable interest in significantly increasing the utilization of the large domestic resources of coal. To date, the primary focus of attention has centered on examining the potential of using more coal for increased electrification. While increased production of electricity is desirable in a number of applications, its additional contribution to overall U.S. energy supply will be limited by cost, efficiency, environmental, and other factors.

A major alternative method of using coal is the production of high Btu or pipeline quality synthetic gas from coal. While the technology for coal gasification has not been commercially demonstrated in the U.S., such applications are now feasible. Moreover, production of gas from coal offers the opportunity to make use of the existing gas pipeline transmission and distribution system in the U.S.

A major U.S. energy policy issue, given the increased desirability and benefits of using coal, is the extent to which emphasis should be given to accelerating the introduction and widespread application of coal gasification technology as opposed to using coal primarily to generate electricity. The resolution of this issue has significant implications for energy regulatory and developmental decisions especially those related to pricing of supplemental coal gas supplies.

This paper provides a comparative analysis of coal gasification and coal-fired electric generation of energy destined for the residential market on the basis of: production and end-use efficiencies; environmental degradation; plant capital requirements; production and transportation costs; and production and end-use energy costs.

EXECUTIVE SUMMARY OF RESULTS OF ANALYSIS

In comparing coal consumption for electric generation and coal consumption for production of pipeline quality (high Btu) gas, the following results were obtained:

On the basis of efficiency of the utilization of the energy content of the coal, gasification of coal is estimated to be considerably more efficient than coal electrification.

Using conventional technologies at the residential end-use, the overall system efficiency is 36 percent for coal gas and 25 percent for electricity.

Using advanced technologies at the end-use (heat pumps), the efficiency advantage of coal gas is substantially higher in almost all regions of the country with the greatest advantage for coal gasification in the most northern parts of the continental U.S. (62 percent for coal gas versus 35 percent for electricity).

From an environmental standpoint, coal gasification plants would result in significantly less air pollution, would generate less solid wastes, and would use far less water than a coal-fired electric power plant producing the same amount of useful energy.

For comparable size plants, air emissions are between 9 and 12 times less for coal gasification, depending on the category.

With respect to water use, a coal gasification plant is estimated to consume 88 percent less water than a comparable coal-fired electric plant.

With respect to the cost of the energy to the end-user, coal gasification has substantial advantage over coal electrification, even when advanced end-use technologies are employed.

For current technologies (i.e. using electric resistance heating and conventional gas furnaces), the average residential cost of energy used would be about $7/MMBtu for coal gasification vs. about $14/MMBtu for electricity from coal.

Using advanced space heating technologies (i.e. heat pumps), the cost of energy from gas produced from coal is between $4 and $5/MMBtu depending on the geographical area compared with $7 and $10/MMBtu for electricity for the same area.

With respect to plant capital investment, for the same amount of delivered energy a coal gasification plant requires about one-third the capital investment of a coal-fired electric plant delivering the same amount of usable energy. When end-use efficiencies are considered, a coal gasification plant requires about one-half the capital investment of a coal electric plant.

A 250 billion Btu per day coal gasification plant would cost about $1.3 billion whereas an equivalent coal electric plant would cost about $2.7 billion.

PRODUCTION AND END-USE EFFICIENCIES

Lurgi coal gasification technology is expected to have an overall thermal efficiency of production of 71 percent.[1] This conversion efficiency includes conversion by-products (liquid fuel and chemicals) that are marketable. For purposes of this analysis, coal gasification conversion efficiencies credit roughly half of the by-product as energy and half as non-energy, resulting in an overall plant efficiency of 65 percent. Capacity utilization is estimated at 90 percent for the gasification facility.

The coal-fired electric generating efficiency used in this analysis is based on western subbituminous coal with flue gas desulfurization (FGD). The thermal efficiency of production used is 32.8 percent and the plant capacity utilization is estimated at 70 percent.[2]

Residential end-use efficiency can vary widely depending on a number of factors, including the kind and age of the appliance, frequency of maintenance, etc. For purposes of this analysis, average rated efficiencies for the natural gas or electric home appliance have been used.

Table 1 shows average residential end-use efficiency for natural gas and electricity with conventional and advanced home appliances. For conventional appliances, the average residential end-use efficiency is based on the 1968 national residential consumption pattern for the four gas or electric appliances (space heating, water heating, cooking, clothes drying). For advanced appliances, conventional space heating has been replaced with thermally activated (gas-fire) heat pumps or electric heat pumps. Inclusion of both electric and gas heat pumps in this analysis is appropriate since electric heat pumps are available today and commercial availability of gas-fired heat pumps is expected in the same time frame (early 1980's) as the first commercial coal gasification facility.

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[1] C. F. Braun and Company Interim Report, Factored Estimates for *Western Coal Commercial Concepts*, October 1976.

[2] Electric Power Research Institute Final Report, *Coal-Fired Power Plant Capital Cost Estimates*, January 1977.

Heat pump efficiencies vary due to climatic conditions. For this analysis, six cities have been chosen as representative of the range of U.S. climatic conditions. Since heat pumps include both heating and cooling cycles, cooling has been accounted for in the end-use seasonal performance factor (measure of efficiency).

TABLE 1.—RESIDENTIAL END-USE EFFICIENCIES[1]

	Conventional 4 appliance[2]		Advanced 4-appliance performance factor[3]	
	Gas	Electricity	Gas	Electricity
Atlanta, Ga			90	185
Concord, Mass			109	130
Houston, Tex			82	198
Philadelphia, Pa	64	94	102	164
Seattle, Wash			110	168
Tulsa, Okla			99	178

[1] Based on 72 pct of energy consumed by space heating, 19 pct water heating, 7 pct cooking, and 2 pct drying. Because of the lack of data, residential energy consumption patterns for the 6 urban areas was not accounted for in this analysis; however, it is expected these differences would result in only small variation to the average residential end-use efficiency.

[2] Conventional gas appliance efficiencies: 66 pct space heating, 65 pct water heating, 40 pct cooking, and 65 pct clothes drying. Conventional electric appliance efficiencies: 98 pct space heating, 91 pct water heating, 75 pct cooking, and 75 pct clothes drying.

[3] Heat pump seasonal performance factor: Atlanta (gas 1.03, electric 2.20); Concord (1.29, 1.46); Houston (0.92, 2.38); Philadelphia (1.20, 1.92); Seattle (1.31, 1.84); and Tulsa (1.15, 2.12).

Combining conversion, transmission and distribution, and residential end-use efficiencies provides a measure of the total system efficiency of coal gasification and coal-fired electric generation. Table 2 shows total system efficiencies for both conventional and advanced (i.e. heat pumps) end-use appliances. Except in Houston when using advanced end-use technologies, total system efficiency for coal gasification is considerably higher than coal electricity.

TABLE 2.—PERCENT OF COAL BTU'S DELIVERED AS USEFUL RESIDENTIAL ENERGY

	Total system efficiency (percent)			
	Conventional[1]		Advanced	
	Gas	Electric	Gas	Electric
Atlanta, Ga			51	40
Concord, Mass			62	35
Houston, Tex	36	25	46	53
Philadelphia, Pa			58	44
Seattle, Wash			62	43
Tulsa, Okla			56	48

[1] Sample calculation using conventional appliances:

	Mining and Trans.	Conversion	Trans. and Dist.	End-use	Total system
Coal Gas	89.5	65.0	97.0	64	36
Coal Electric	89.5	32.8	91.2	94	25

Based on the above calculations assuming conventional appliances, nearly 30 percent less coal is required for a coal gasification facility supplying similar quantities of useful end-use residential energy than that required for a coal-electric facility.

ENVIRONMENT

From an environmental perspective—including physical, chemical, biological, and socioeconomic impacts—coal gasification would produce significantly less environmental effects than coal electrification at every major step in the production and transportation chain. Coal gasification versus coal burning, underground pipelines versus unit trains or overhead high voltage power lines, etc. (See Table 3). Indeed, coal gas plants would readily conform to the Clean Air Act, even with the proposed 1977 amendments on non-degradation.

Air quality.—The President's Council on Environmental Quality recently found that commercial-scale gas plants will cause about one-tenth the air pollution of equivalent coal electric plants, even those that use the best pollution control technology available.[3]

Non-degradation.—Proposed 1977 Clean Air Act amendments concerning prevention of air pollution in areas that are presently clean would impose severe siting restrictions on coal-electric power plants. The restrictions on coal gasification plants, however, will be negligible. A recent FEA/EPA study[4] suggests that all the coal gasification plants that were proposed in 1976 for inclusion in the federal loan guarantee program would comply with, and even exceed, the most stringent version of the non-degradation amendments presently before the Congress.

In fact, as shown in Table 4, numerous expansions of coal gas plants beyond the initial 250 MMcf/d level would theoretically be allowable at the proposed sites under the nondegradation rules, while not even a single coal-fired power plant of equivalent energy output could be built and operated at some of these same sites under the proposed law.

Water resources.—Proposed coal gasification plants would consume 5 to 10 times less water than equivalent coal-fired or nuclear electricity generating plants (see Table 3), and would require only a small portion of available water supply in each region.

Land impacts.—According to ERDA's draft programmatic EIS,[5] the mining activities associated with a single 250 MMscf/d coal gasification plant could cumulatively affect 6,020 acres of land over a 20-year period in the Four Corners region, for example. In any single year, only a small portion of this acreage would be disturbed or out of production. In regions such as this, it is believed that the range and agricultural productivity of Western surface-mined lands can be largely restored, and often enhanced beyond previous levels. Proposed surface mining legislation currently before the Congress would impose little unanticipated new costs to most of the proposed near-term Lurgi coal gasification projects.

TABLE 3.—SUMMARY COMPARISON OF ENVIRONMENTAL IMPACTS OF 2 ENERGY-EQUIVALENT PROJECTS

	High-Btu coal gasification plant (250 mmcfd)	Kaiparowits powerplant (3,000 Mwe with scrubbers)
Air emissions (LB/HR):		
Particulates	180	1,070
SO_2	450	4,300
NO_x	1,780	20,830
CO	90	1,200
HC	30	360
Water requirements (acre-feet per year	6,300	54,300
Solid wastes (tons per day)	1,400	5,100

Notes: All figures rounded. Proposed coal electric powerplant at Kaiparowits was to include wet cooling towers and underground mining, both of which tended to increase its projected water use.

Sources: Radian Corp., "A Western Regional Energy Development Study: Primary Environmental Impacts," vol. II, prepared for the Council on Environmental Quality and the Federal Energy Administration under contract No. EQ4AC037 August 1975; "Final Environmental Impact Statement on the Proposed Kaiparowits Project," U.S. Department of the Interior, March 1976.

[3] *A Western Regional Development Study: Primary Impacts*, prepared for CEQ under contract No. E04AC037, by Radian Corporation, August 1975.

[4] U.S. Environmental Protection Agency, *Summary of EPA Analysis of the Impact of the Senate Significant Deterioration Proposal*, April 1976.

[5] Synthetic Fuels Commercialization Program, Draft Environmental Statements, December 1975, Energy Research & Development Administration and Department of the Interior.

TABLE 4.—EFFECT OF NONDEGRADATION RULES ON HIGH-BTU COAL GASIFICATION AND COAL-FIRED ELECTRIC GENERATING STATIONS[1]

Potential sites	Nearest protected area (class I)	Number of plants: Coal gas (250 MMcfd)	Number of plants: Coal electric (3000 MWe)
San Juan County, N. Mex.	Canyon DeChelly National Monument (35 mi); Mesa Verda National Park (50 mi).	8 plants	None.
Mercer County, N. Dak.	Lost Wood National Wilderness (90 mi); Theodore Roosevelt National Memorial Park (81 mi).	9 plants	None or 1.
Converse County, Wyo.[2]	None	8 plants	Do.

[1] Adapted from reference 2, p. 7. Source for coal gas plants: Environmental Research and Technology, Inc., Impact Assessment of Significant Deterioration Amendments to the Clean Air Act on Siting of Synthetic Fuel Plants, April 1976. All figures rounded. Results based on meteorological assumptions and 250 MMscf/d Lurgi coal gasification plants using best available control technology (BACT).

[2] Coal energy production at this site is limited by class II SO_2 24-hr increments.

Solid wastes.—Solid wastes from a coal gasification complex include spent ash remaining after coal gasification, sludges generating during the water treatment process, and spent limestone from the sulfur dioxide scrubbers installed on waste gas streams. The quantities of solid waste are significantly less than those associated with a coal electric plant with the same energy output.

CAPITAL REQUIREMENTS

On the basis of equivalent quantities of end-use energy from conventional appliances (see Production and End-Use Efficiency Section), a unit-size coal gasification facility, 250 million cubic feet per day (MMcfd), produces the same amount of energy as a 3,000 megawatt (Mwe) coal-fired power generating station. When advanced appliances are used, the size of either facility, in terms of a fixed amount of usable energy consumed in the end use, would vary in each region since residential end-use efficiencies vary.

Based on recent capital cost estimates of $1.3 billion for a 250 MMcf/day western coal gasification facility and $895 per kilowatt of installed capacity for a western coal-fired electric facility with flue gas desulfurization, a coal gasification facility requires roughly half the capital investment of a coal electric facility delivering the same quantities of energy to the end-use ($1.3 billion versus $2.7 billion). Table 5 shows unit investment on the basis of delivered and useful end-use energy. Even with the higher efficiencies available from advanced electric appliances, the investment savings from coal gasification in all cases is nearly 50%.

TABLE 5.—UNIT CAPITAL REQUIREMENTS

[Cost in dollars per annual MMBtu]

	Delivered		Useful end-use: Conventional		Useful end-use: Advanced	
	Gas	Electric	Gas	Electric	Gas	Electric
Atlanta, Ga	14.69	47.17	22.95	50.18	16.32	25.49
Concord, Mass					13.48	36.28
Houston, Tex					17.91	23.82
Philadelphia, Pa					14.40	28.76
Seattle, Wash					13.35	29.85
Tulsa, Okla					14.84	26.50

Sources: C. F. Braun & Co. Interim report, Factored Estimates for Western Coal Commercial Concepts, October 1976. Electric Power Research Institute Final Report, Coal-Fired Power Plant Capital Cost Estimates, January 1977.

TABLE 6.—DELIVERED RESIDENTIAL ENERGY PRICE CALCULATION

[In 1976 dollars]

	Coal gasification	Coal electricity with scrubbers
Capacity [1]	[8] 250	[9] 3,000
Annual generation [2]	[10] 91,300,000,000	[11] 18,396
Capital cost	$1,300,000,000	$2,700,000,000
Annual fixed charge [3]	$213,100,000	$442,500,000
Cost per million Btu:		
Capital charge [4]	$2.34	$7.05
Fuel cost [5]	.72	1.31
Operating and maintenance [6,7]	.96	.59
Credit for byproducts [6]	(.72)	NA
Transmission and Distribution [6,7]	1.15	4.82
Total	4.45	13.80

[1] A 250 MMcfd coal gas plant delivers 155.2×10[9] Btu per day through conventional residential appliances. A 3,000 MWe coal plant delivers 153.7×10[9] Btu per day through conventional appliances.
[2] For coal gas average daily send-out is 250 MMcfd and peak day is 275 MMcfd. For coal electric average daily send-out is 50,400,000 kWh.
[3] Calculated at 16.39 percent per year over facility life. Based on 75/25 debt to equity, 10.75 percent interest, 15 percent return on equity, 2 percent taxes (other than income), 50 percent income tax, and 35-yr life.
[4] Annual fixed charge divided by annual generation.
[5] Based on 7.50/ton subbituminous Western coal.
[6] C. F. Braun & Co. Interim Report, Factored Estimates for Western Coal Commercial Concepts, October 1976. Gas transmission costs calculated on the basis of 300-mi transmission. Distribution costs are taken from data in 1975 Gas Facts. Residential distribution cost is calculated by subtracting the average price paid by utility companies from the average residential price charged by utility companies. An escalation factor of 5 percent was then used from mid-1975 to mid-1976.
[7] Electric transmission and distribution cost is the difference between average residential revenues per kilowatt-hour and the average cost of production for investor-owned electric utilities. The average residential revenues per kilowatt hour are given in the 1975 Edison Electric Institute Statistical Yearbook. The average production cost is a computed figure obtained by adding average variable production costs as given in the above reference and estimated fixed capital charges. These fixed charges are calculated by allocating 45 percent of net total electric utility plant assets to the generation plant and multiplying it by the 1975 embedded capital cost of just over 12 percent. The fixed and variable costs are then combined and allocated over energy sales for investor-owned utilities in 1975. The differential resulting from the subtraction of production cost from average residential revenues per kilowatt-hour is then escalated at a 5 percent annual rate from mid-1975 to mid-1976.
[8] Million cubic feet per day.
[9] Megawatts electrical.
[10] Cubic feet.
[11] Gigawatthours.

PRODUCTION AND TRANSPORTATION COSTS

Table 6 shows production and transportation cost estimates for coal gasification and coal electricity. Production costs were calculated on an incremental basis, using standard regulated utility accounting procedures. Transmission costs assume use of existing lines and approximately 300-mile transmission from conversion facility to consuming market. Distribution costs are calculated on the basis of 1976 average residential distribution costs.

The costs of generation are particularly sensitive to two factors—the capital cost of the facility and the price of coal. For this analysis the facilities were assumed to be located in the west, with operation beginning in 1982, and using Montana sub-bituminous low sulfur (Powder River) coal. Although national air quality standards could most likely be met without flue gas desulfurization equipment (scrubbers), more stringent State standards in many areas may necessitate their use. As a consequence, scrubbers and the resulting energy losses have been included in the calculations for the coal-fired electric generating facility.

The coal gasification advantages of greater conversion efficiency and lower capital cost per unit output cited earlier are clearly reflected in the delivered cost of coal gasification which is nearly one-third that of coal electricity ($4.45 versus $13.80/MMBtu).

RESIDENTIAL END-USE ENERGY COSTS

Delivered energy costs do not, however, reflect the entire comparative cost, since residential end-use efficiencies are generally higher for electric appliances. By dividing the delivered energy cost by the average residential end-use efficiency, an average residential cost per useful Btu of energy is calculated (see Table 7).

TABLE 7.—RESIDENTIAL END-USE ENERGY COSTS

City	Cost in dollars per MMBtu of useful energy consumed			
	Conventional		Advanced	
	Coal gas	Coal electric	Coal gas	Coal electric
Atlanta, Ga	6.95	14.68	4.94	7.45
Concord, Mass			4.54	10.61
Houston, Tex			5.43	6.96
Philadelphia, Pa			4.35	8.41
Seattle, Wash			4.05	8.73
Tulsa, Okla			4.49	7.75

Table 7 shows for the average residential user with conventional appliances (gas furnace or electric resistance space heating), that the average price per million Btu (MMBtu) of useful energy consumed by the four major home appliances (space heating, water heating, cooking, and clothes drying) is $6.95 for coal gas versus $14.68 for coal electricity. Even when advanced appliances are considered, the average residential consumer would still pay less (ranging from 24 percent to 63 percent less) for gas made from coal than for electricity from coal.

The CHAIRMAN. Next, we will hear from Mr. E. L. Bud Stewart, executive director, Energy Consumers and Producers Association, accompanied by Mr. Paul McCully, president, Wil-Mc Oil Corp., Mr. Max Berry, counsel, Energy Consumers & Producers Association.

STATEMENT OF E. L. BUD STEWART, EXECUTIVE DIRECTOR, ENERGY CONSUMERS & PRODUCERS ASSOCIATION; ACCOMPANIED BY COCHAIRMAN PAUL McCULLY, PRESIDENT, WIL-MIC OIL CORP., AND MAX BERRY, COUNSEL, ENERGY CONSUMERS AND PRODUCERS ASSOCIATION

Mr. STEWART. Thank you very much, Mr. Chairman and members of the committee. My name is Bud Stewart; I am executive director of the Energy Consumers & Producers Association of Seminole, Okla.

Mr. McCully, cochairman of the association on my left, had the distinction of being the most active independent operator in Oklahoma last year, drilling some 64 oil and gas wells, and you mentioned Mr. Barry on my right, he is our Washington counsel.

The Energy Consumers & Producers Association has 50 members—primarily independent producers of oil and gas—as well as a sprinkling of consumers and citizens in some 14 States. In addition to our efforts to achieve adequate energy legislation, we have substantial Federal litigation now pending in Federal courts against the Federal Energy Administration because we feel that some of their rulings and regulations actually inhibit our members from producing the maximum amount of oil and gas.

Also, we have recently formed a coalition with the Independent Cattlemen's Association, feeling that food producers and energy producers have much in common, and we think that this will be of benefit to all such consumers in the future.

The basic question has to be asked—why has this administration and unfortunately, the House of Representatives, so totally, persistently, and even stubbornly risked the surrender of the future economic and perhaps military well-being of this country to the OPEC cartel?

President Carter, Secretary Schlesinger, and other high officials have all stated that they believe our domestic industry cannot find sufficient oil and gas to pull us through the remainder of this century. In 1930, it was common knowledge by all oil experts that no oil existed in Rusk County, Tex. Three years later, the east Texas field contained over 6,000 wells and the largest field in the world had been discovered. Independent oil operators discovered the east Texas field; independent oil operators drill 87 percent of the exploratory wells in our country; independent oil operators find 8 percent of the new fields in the United States; and they produce some 54 percent of the reserves in this country.

We feel the House bill is merely a major company bill. This bill is really going to hit the independent operator more than it is the major company at a time when over 97 percent of the land area in this country has not yet been condemned by the drill bit.

Can a truly responsible Government run the risk of refusing to provide all incentives necessary to assure that every possible prospective well is drilled? We will see. Maybe the President is right in the long run. Maybe we cannot find it.

But are we willing to run the risk, by preventing us from drilling every prospect? If that were to happen, I think the administration will have been guilty of perpetrating the biggest rip-off in the history of our times.

If we, as the President suggests, are engaged in the moral equivalent of war, then we emphatically say, give us the tools and we can do the job.

We commend the President for recognizing that we have an energy crisis. We commend him for some of the conservation methods, but again, his program is woefully weak in providing the incentive for new production.

We have come now to the point where this committee primarily and the Senate of the United States have the responsibility of trying to right this wrong. These crucial incentives that we need must be based on a system of pricing that reflects the actual cost of oil and gas exploration and production and provides incentives for the investment of the huge sums of money needed to do the job. Some have estimated as much as $265 billion of investment money needs to go into the drilling of oil and gas wells in the next 10 years.

Our national goals should be to provide incentives to drill 80,000 wells per year by the early 1980's. If the 41,000 wells drilled in this country last year can locate 2 billion equivalent oil barrels of new reserves, there is no reason to doubt that 80,000 wells, or twice as many, would not find twice as much in the way of reserves.

The Federal Government policy in the past 20 years has really put us in the shape that we are in. It was the national policy of this country to import cheap, foreign crude oil, until it got to the point that over 50 percent of our total needs was imported. Now as we all know, it is no longer cheap, but highly expensive foreign oil, which we are importing in such great quantities.

I think that there is one thing that we ought to recognize. With the current upper-tier price, I have heard many say that we are drilling more wells now, so obviously there has to be an incentive, or people would not drill. I would submit that the upper tier price of $11.28 is perhaps sufficient to sustain a very modest exploration program for previously known but uneconomic prospects, but of course, the higher price of oil could sustain a larger exploration program and that is what we would like to propose.

I think this can be backed up by the fact that last year the wildcat success ratio was the highest it has been since 1967. In other words, more wildcat wells were successful, percentagewise, than ever before. Also, though, I feel that it is important to recognize that less oil was discovered per well drilled last year than any other. Instead of drilling deeper, we were drilling more shallow prospects.

So this would point out to me that the $11.28 was sufficient incentive to drill very marginal prospects, when we ought to go out and drill for elephants and drill for the big ones.

It is obvious, statistically, that $11.28 is insufficient to do that.

One thing that is very important is that the President's bill and the House bill provide an incentive to produce less oil, and I want to explain it this way. There is currently a stripper well provision, as you all know. That means that a stripper well producing less than 10 barrels, can get the world price at $13.

The CHAIRMAN. I am not sure I understood what you said. You said that $11.28 was sufficient to get the shallow wells developed but not to drill the deep wells. Is that what you mean?

Mr. STEWART. Yes. I would explain it this way. Someone said we are drilling more wells, therefore there has to be sufficient incentive. I am not denying that we are drilling more wells and there has obviously got to be enough incentive in $11.28 to drill more wells, but the kind of prospects that we are drilling are not the prospects that are going to find the big reserves. They are close in. We are drilling shallower wells than we used to historically. We need to keep drilling deeper and deeper each year, where the bigger reserves are going to be found. But we are not doing that; it is reversing.

I am saying, in effect, we need more than $11.28 to go out and hunt for the elephants which are going to find the large number of reserves that the country needs. But just as important, I think that we have to recognize that the stripper price is an incentive to produce less oil and I would like to explain it this way.

If a well is making 12 barrels, or 13 barrels, a day, there is not sufficient incentive at $5.25 a barrel to expend the effort and cost to go in and work that well, or improve it, or even keep it on a sustained level.

There is a great incentive in the $8 more per barrel to let it fall under 10 barrels a day so it will qualify for stripper. So I think that a decontrol program to enable us to have a higher price will assure us of not only finding more oil and gas and drilling more wells, but maintaining the wells that we have now.

I think that is extremely important.

I would like to move rapidly to the specifics of some of our recommendations. We request that the price of new oil and gas be fully decontrolled in order that we can raise the necessary capital to find new wells and to sustain the wells that we now have.

It is also very important that we have a definition of new oil. The House Ways and Means Committee recommended that a property definition be put in, that any well could qualify for new oil if it is drilled on a lease that did not produce oil 90 days prior to April 20. That was removed on the floor of the House, and we need to get it back.

We would like to have a gradual decontrol of lower and upper tier prices, thinking again that that is where our capital has to come from.

Also, we would like to request that a plowback be considered. When we drill, we independents drill up every dollar we get anyway. The wellhead tax in the President's proposal is a 100-percent tax. We say, give us the increase over a period of time, all of the increase. If we do not drill it up, we will give it back in a tax, tax us at 100 percent of the increase. In the meantime, we have solved this problem of finding additional oil and gas.

Also, we would like to recommend that the stripper well amendment be altered to recognize the difference in operating costs between various depths.

It costs more to operate a well at 9,000 feet, obviously, than it does at 2,000 feet, yet 10 barrels a day is the magic number, no matter how deep the well is. To preserve those wells, you should have incremental increases to get them into the stripped category.

I would like to mention the intangible drilling expenses as a very important thing to the independent operator, to bring outside income into the drilling ventures.

Even though the President has already agreed to exclude intangible drilling costs—not in excess of income—from the minimum tax for 1 year—and we are very thankful for that—that ought to be a permanent program. After all, the intangible drilling expense is an expense and the oil and gas business right now is the only business in this country that is taxed on expense. Everybody else gets to write it off. We cannot do that, and we would like to have that as a permanent factor.

We would be very happy to answer any questions that you might have. I request that a full written statement be included in the record, in addition to my oral remarks.

The CHAIRMAN. Thank you very much. You summarized your statement; I want to assure you that I will carefully study this and do justice to your attached appendix.

Any questions, Senator Packwood?

Senator PACKWOOD. No, sir, no questions.

The CHAIRMAN. Thank you very much.

Mr. STEWART. Thank you very much.

[The prepared statement of Mr. Stewart follows. Oral testimony continues on p. 384.]

TESTIMONY OF THE ENERGY CONSUMERS AND PRODUCERS ASSOCIATION

SUMMARY

The Carter energy program, as adopted by the House of Representatives is seriously deficient in that it does not provide the incentives necessary for the full development of domestic sources of oil and gas. The current House legislation with its price controls and 10 percent wellhead tax, guarantees that we will continue to take too much money from our own economy, including those segments of our economy which are capable of increasing our domestic petroleum reserves, in order to pay for high cost foreign oil and gas imports.

The Congress must adopt energy legislation which provides the following measures:

1. Full decontrol of new oil and gas combined with a definition of new oil and gas based on the concept of a property not in production 90 days prior to April 20, 1977.
2. Gradual decontrol of "lower" and "upper tier" oil in order to stabilize existing production and to provide capital for the exploration and development of new sources of oil and gas. Decontrol would be combined with a "plowback" tax (up to 100 percent if necessary) to insure that increased revenues generated be utilized to develop increased reserves.
3. Simplified and automatic mechanisms to permit producers to recoup the variances in costs involved in different wells due to differences in depths, etc.
4. Tax incentives to encourage the development and utilization of enhanced recovery techniques.

STATEMENT

Mr. Chairman and members of the Committee, my name is Bud Stewart, Executive Director of Energy Consumers and Producers Association of Seminole, Oklahoma. I have with me today, Paul McCully, President of Wil-Mc Oil Company of Dallas, Co-chairman of our Association. Mr. McCully's firm last year drilled some 64 wells in Oklahoma, marking him as the most active independent operator in the State and second only in total wells drilled to Standard Oil of Indiana. Also present is Mr. Max N. Berry, Washington Counsel of the Association. The Energy Consumers and Producers Association (ECPA) is an organization of 250 members—primarily independent oil and gas operators with a sprinkling of royalty owners, and other interested citizens in 14 states from Massachusetts to South Texas. The purpose of the ECPA is to provide for the adoption of laws and policies which will better enable its membership to develop U.S. petroleum resources in order to ease the growing national energy crisis. Moreover, the Association has extensive federal litigation underway to rid the independent producer of unfair bureaucratic rulings of the Federal Energy Administration which greatly inhibit our ability to maximize production. In addition, the ECPA has entered into a formal affiliation with the 116,000 member Independent Cattlemens Association to form the Independent Food and Energy Producers Assocation. The aim of this coalition is to secure adequate supplies of energy and food at the most reasonable cost for the use and benefit of American people.

We appreciate the opportunity to testify before you today. The basic question to ask is—why has this Administration and, unfortunately, the House of Representatives, so totally, persistently and stubbornly risked the surrender of the future economic and perhaps military well being of this country to the OPEC cartel? President Carter, Secretary Schlesinger and other high officials have all stated they believe our domestic industry cannot find sufficient oil and gas to pull us through the remainder of this century! In 1930 it was common knowledge by all oil "experts" that no oil existed in Rusk County, Texas. Three years later the East Texas field contained over 6,000 wells and the largest field in the world had been discovered. Independent oil operators discovered the East Texas field; independent oil operators drill 87 percent of the exploratory wells in our country: and independent oil operators find 82 percent of the new fields in the United States.

Over 97 percent of the land area of the United States has not been condemned by the drill bit! Can a truly responsible government run the risk of refusing to provide all incentives necessary to assure that every possible prospect is drilled? In the long run, the Administration may be correct—but if they are wrong, there should be little doubt they will have precipitated the biggest "ripoff" of all time! If we, as the President suggests, are engaged in the moral equivalent of war, then we emphatically say "Give us the tools, and we will do the job." While we commend the President for recognizing the fact that we do have an energy crisis, our

Association strongly believes the present legislation to be deficient in two serious respects: (1) It does not adequately mobilize U.S. producers to explore for potential domestic energy reserves, and (2) its energy conservation proposals rely too greatly on complicated bureaucratic mechanisms to achieve its purposes.

What is needed is production incentives, and the only hope for the establishment of such incentives now lies with the U.S. Senate and particularly with this Senate Committee on Finance, which has sole jurisdiction over U.S. taxation. These crucial incentives must be based on a system of pricing which reflects actual costs of oil and gas exploration and production and provides an incentive for the investment of the huge sums of money needed to undertake that development. These incentives must also be based on a system of taxation which, rather than inhibiting the production of oil and gas in the United States, actually promotes such development. Our national goal should be to provide the incentives to drill 80,000 wells per year by the early 1980's. If the 41,000 wells drilled in 1976 can locate 2 billion equivalent barrels of new reserves, there is no reason to doubt that 80,000 wells drilled would add 4 billion barrels of new reserves each year. However, under the present circumstances, statistics indicate we are currently drilling some 4–6 percent fewer "wildcat wells" than we should be drilling.

Federal government policy has for the past several decades served to curb domestic crude oil production in favor of what used to be cheaper foreign petroleum imports, resulting in a steady decline of domestic exploration and production. The new program recently enacted by the House of Representatives will likely curb domestic crude oil production in favor of now highly expensive foreign imports of petroleum products. The current upper tier price of $11.28 per barrel is perhaps sufficient to sustain modest exploration programs of previously known but uneconomical prospects. However for the long term, the industry requires an enormous amount of capital to develop unexplored regions, to implement higher cost techniques involved in enhanced recovery projects and—generally little recognition is paid to this important point—to provide incentives for the continued full production of existing oil wells.

If one compares the current price for stripper production of $13.50 per barrel, some two and a half times greater than the price for lower tier crude oil, it is obvious that as the costs of labor, repairs, equipment. services, etc. rise. there remains little incentive to maintain production of declining wells since lower production in a well will actually provide more revenue. Thus the House Energy program would serve to decrease not only future exploration and production of oil and gas but could have a very limiting impact upon existing wells in practice.

The Energy Consumers and Producers Association strongly feels that the best domestic energy policy would be to eliminate all price controls on the production of oil and gas and likewise eliminate the proposed wellhead taxes which have the simple effect of removing most oil revenues from that sector of the economy which is responsible for the development of U.S. petroleum resources. However, we recognize the conflicting interests represented in this legislative process and we therefore would propose the following steps which, while not optimizing the production of oil and gas in this country, would constitute a legislative framework which should be acceptable to the Congress of the United States. Accordingly, the Energy Consumers and Producers Association strongly urges that the energy legislation of 1977 accomplish the following needs:

1. *Decontrol of new oil and gas prices. plowback tax mechanism.* The price of new oil and gas must be fully decontrolled so that the continually increasing costs of exploration and development can be recouped and so that sufficient capital will be attracted to the development of oil and gas resources to insure that the United States fully utilize its available petroleum resources. In the event that decontrol does not occur, the Association supports the adoption of any reasonable tax system which would guarantee that revenues generated from the production of new oil and gas be channeled back into the development of future petroleum resources. This is a course which independent oil and gas producers have and will continue to follow in any case. In addition. the definition of new oil should be changed to that originally adopted by the Ways and Means Committee. Under this definition, new oil would be defined as oil produced on a property on which there was no commercial production in the 90-day period prior to April 20, 1977. The current definition of new oil in the House bill is unrealistic and would serve as a disincentive to domestic oil production.

2. *Gradual decontrol of "lower" and "upper tier".* The importance of decontrol of lower and upper tier oil is something that is significant and up to this point not fully recognized. The cost of maintaining existing oil production increases every year and will continue to increase until any fixed price level is exceeded. The discrepency between lower tier pricing and stripper pricing is such as to remove any incentive to incur the costs necessary to maximize and maintain production of declining wells. As an alternative, this Committee should give serious consideration to decontrol of lower and upper tier oil combined with a system of taxation which insures that increased revenues generated therefrom will be used: (1) to maintain existing production and (2) to provide the necessary capital to explore for additional oil and gas reserves.

This would be a so-called "plowback" tax provision. Since the Administration proposed and the House passed an energy program requiring a 100 percent wellhead tax on increased oil prices, our Association would support 100 percent taxation of the increased revenues if such additional money were not used as added investment in exploration and production. This plowback provision would assure the American public that there would be no windfall or excess profit. The American independent oil and gas man historically drills up all of his income anyway.

3. *Pricing and taxation mechanisms should more accurately reflect differences in production costs.* It costs more to produce oil from zones 9,000 feet deep than it would cost to produce oil from zones only 2,500 feet deep. Any program adopted by the Congress should recognize these variances in cost and provide a simple and automatic method of relief. In addition, even though there seems to be wide knowledge of the fact that tertiary recovery techniques provide the potential for recovery of enormous quantities of oil and gas, there seems to be little in the current House legislation which would encourage the development of new secondary and repressuring programs which likewise will maximize production potential in existing fields. After all, most fields still hold over 50 percent of the oil in place and producers should receive price incentives to develop any method to stabilize as well as increase production in those fields.

The Energy Consumers and Producers Association feels that the issues involved in the development of effective energy legislation should be viewed from a new perspective:

Why is it that decontrol of oil is viewed as a ripoff of the American consumer and a source of excess profits for U.S. producers, when in fact the proposed House legislation simply guarantees an even greater ripoff of American consumers to foreign producers with a 100 percent loss of the oil payments to the American economy? Money in the hands of U.S. oil producers has always and will continue to lead to the production of U.S. domestic oil resources, to the providing of thousands of jobs not only in the oil industry, but also in most major U.S. industries, and to a source of general tax revenues throughout the country. On the other hand, money in the hands of OPEC producers is a total loss to the United States, and the major reason for our rapidly increasing trade deficits.

Why is it that decontrol of natural gas prices is also considered to result in unnecessarily high costs to U.S. consumers when in fact the continued rapid depletion of existing resources and the failure to develop new future resources will lead to the necessary use of synthetic natural gases, coal degasification and other substitutes which are today already much higher in cost than natural gas sold at decontrolled prices would be? With natural gas we are in fact perpetuating the mistake which we have made for the past twenty years.

Why is it that an Administration which has pledged itself to the reduction of government has now created an agency with over 20,000 people whose prime purpose is not to increase the production of oil and gas but to inhibit that production through an artificial system of price limitations and allocation mechanisms? Is the cost of the salaries of these 20,000 people and the inhibiting impact of the agency on oil and gas production less than the cost of a fully free market system ostensibly espoused by the current administration?

Why is it with the huge amounts of revenue which would be developed through the wellhead tax system, that so little of that money will be channeled into the development of domestic oil and gas which is and will remain our primary source of energy for the next several decades?

Why is it that the political decisions represented by the House legislation have so little to do with the actual economic factors controlling the maintenance of existing production and the development of future oil and gas production in the United States? All major pieces of legislation require political compromises reflecting the conflicting interests of those segments of the economy affected by such legislation. However in the case of the energy legislation, the decisions seem to have very little relation to that sector of the U.S. economy which actually produces U.S. oil and gas and which has the greatest knowledge of the factors influencing such production.

Historically the independent "wildcatter" has been the segment of the industry finding most of new oil and gas reserves in the United States. Given proper incentives this group has never failed to locate and produce the oil and gas required for a growing national economy in war time as well as peace time. There are literally thousands of independents willing to meet this challenge and take the risk. They will "plowback" their returns—this fact is also historical. If the goal of President Carter and the Congress is to increase domestic supplies of oil and gas, ways must be found to encourage the independent producer to continue to do his thing. Since most independents rely on capital from outside the industry to finance the exploration drilling, it should therefore be national policy to encourage outside capital as well as self-generated capital to undertake drilling projects. The positions stated here have been proven to be workable in the past and hold the only promise to work in the future. The surest way to guarantee a nation with permanent domestic shortages is to continue the course of price controls and taxation at the wellhead. The surest way to guarantee that our nation will develop to the fullest extent its own natural resources is to eliminate such price controls and to utilize taxes as incentives and not disincentives for production.

I and my colleagues appreciate the oportunity to testify before the Committee today and we will be happy to answer any questions and provide any information which the Committee may desire.

Appendix

The attached appendix contains testimony given by Mr. C. H. Keplinger on behalf of the Energy Consumers and Producers Association before the Ways and Means Committee on May 24, 1977 with respect to the tax aspects of the Administration's energy proposal.

Testimony by C. H. Keplinger on Behalf of the Energy Consumers and Producers Association

Mr. Chairman and members of the committee: My name is C. Henry Keplinger, and I am Chairman of the Board of Keplinger and Associates, Inc. of Tulsa, Oklahoma, and Houston, Texas. I have been an advisor to oil and natural gas companies, United States Government Agencies, and foreign governments for over 30 years. My experience has been in the oil producing branch of the petroleum industry in regard to exploration for oil and gas, determination of oil and gas reserves, and operation of oil and gas properties both in the United States and foreign areas. I represent the Energy Consumers and Producers Association, an interested group of U.S. citizens who believes in the ability of the petroleum industry to find domestic oil and gas reserves to replace the purchase of foreign oil. I am glad to have this opportunity to testify before you today because I can give you some facts on the issue of stimulation of domestic production to replace foreign oil imports.

Public concern over the United States dependence on oil imports has heightened the importance of stimulating domestic oil and gas production. The United States is abundant in domestic oil and gas resources. Last winter's scarcities, particularly natural gas, and increased expensive OPEC oil imports have done much to make the nation extremely conscious of the consequences of the continuing national failure to come to grips with the problem.

We must use our oil and gas resources wisely and efficiently in our homes and factories. Carter's suggestions along these lines—"the moral equivalent of war" is laudable. Programs to conserve energy will strengthen the nation's energy base and all citizens welcome, reluctantly, the opportunity to buckle-down and help. Conservation programs are rewarding, but they do not increase our dwindling oil and gas reserves. I will speak of the facts that support a price incentive to boost our domestic oil output, increase daily oil production and oil reserves. We should have as part of the energy program incentives for oil and gas drilling in the United States to replace foreign oil.

Because so many unsupported statements have been on oil prices I want to make it clear at the outset that I am only speaking of oil prices for oil found and produced from new wells under the present FEA definitions after Congress enacts the National Energy Plan. The proposal is that the oil price from new wells would be "regulated" and not allowed to exceed the United States' delivered price of foreign imported oil which cost us over $35,000,000,000 last year and it is estimated to exceed $40,000,000,000 this year.

This "regulated" price for new oil wells would be the same as is now being paid for imported oil so there could be no "oil rip-off" for the consumer. In addition, the new wells in the United States would be drilled by American labor and equipped with materials produced by American labor in all sectors of the nation—New England States, Middle Atlantic States, Central States, etc.

The consumer would pay the same price for new domestic oil as for foreign imported oil, but there would be no outgo of United States dollars to purchase foreign oil. The development of our domestic oil potential would generate work and business which would create additional Federal and State taxes. This would strengthen the dollar and the economy. The only loser would be the OPEC nations who would sell us less and less imported oil as our domestic drilling increased.

The present FEA oil prices on both "lower and upper tier" would continue to be under FEA surveillance. These prices would remain until the well qualified for "stripper" production. As you know, Congress, in November 1973, exempted stripper oil production (wells that produce 10 barrels per day or less) from controls.

The history of price regulation of the Domestic Oil Industry from August, 1973, to March, 1977, is shown in Appendix A. It will be noted that the Cost of Living Council (CLC) introduced the concept of new and released oil and permitted oil operators to sell certain incremental volumes of crude at world market prices. My recommendation to Congress is to allow world market prices for all new wells in order to stimulate domestic drilling and exploration. This would be the same price paid for foreign imported OPEC oil and would do three things:

1. It would cost the consumer no more than the price paid for approximately 8,000,000 barrels per day of imported oil.
2. It would build up our oil production in excess of 2,000,000 barrels per day and make us less dependent on OPEC and Russian oil maneuvers.
3. It would stimulate the economy by encouraging the drilling of approximately 80,000 wells per year in the future.

The pragmatic scenario to make the nation less dependent on foreign imported oil and curtailment is to make it possible by a price incentive equal to the world price so that the U.S. will drill 80,000 wells per year in the next 4 to 5 years and test the potential producing capacity of our nation's oil resources. This is approximately a 40 percent increase, well within the petroleum industry's ability, over total wells drilled in 1956 when the government regulation of gas prices and the inflow of foreign oil reduced the incentive to drill and explore for oil and gas in the United States. A summary of wells drilled in the U.S. since 1918 to and including 1975 is shown in Appendix B and Appendix C shows the total wells drilled in graphic form.

During 1974, when approximately 1,132 million barrels of equivalent oil were discovered, includes oil, gas, and liquids discovered, the petroleum industry drilled 32,618 wells. By drilling 80,000 wells per year in the future we would have the opportunity to discover an estimated equivalent 2,750 million barrels of oil per year which would replace the purchase of foreign imported OPEC oil and at the same cost, or less after considering taxes generated by the Government, per barrel to the U.S. consumer as the foreign oil. Based on the experience that one third of the equivalent oil discovered would be oil, the new oil discovered would approximate 1 billion barrels per year and add over 2 million barrels of production per day on the average to the U.S. supply.

The domestic production and proved reserves at year end from 1918 to 1975 is shown on Appendix D.

The above scenario of a goal of 80,000 wells per year is based on the following facts.

FACT NO. 1—U.S. OIL AND GAS SUPPLIES AND AVAILABILITY DECLINING UNDER PRESENT PRICE CONTROLS

The protasis of my analysis of Carter's National Energy Plan suggests a strong response must be made to President Carter and Congress. There must be comprehension of the myths and realities of the energy industries by our Washington leaders. It must be understood that domestic oil and gas production must be increased and that the "energy crisis" reality (short supply) is not a lot of bunk pumped up by producers of domestic oil and gas to get higher prices or coal companies to pollute and to desecrate the environment.

As to the U.S. energy supply, we know that oil production, availability and oil reserves are declining. The American Petroleum Institute recently reported U.S. oil production in 1976 was the lowest since 1966, despite increased drilling. The A.P.I. estimated the nation's proved oil recoverable reserves at 30.9 billion barrels as of January 1, 1977. This is a drop of 1.7 billion barrels from the year-earlier figure and compared with a decline of 1.6 billion barrels in 1975. The nation produced 2.8 billion barrels in 1976 compared to 2.9 billion barrels in 1975.

The history of U.S. production and discoveries indicates that yearly discoveries of oil have not equalled yearly oil production for many years. On Chart 1, the top line shows the amount of production since 1960 by years and the bottom line shows the oil discoveries over the same 15-year period. Based on oil reserve data, total U.S. production over a 16-year period was 48.9 billion barrels with discoveries being only 23.3 billion barrels. The U.S. is consuming almost twice as much oil as it produces. The U.S. oil reserves are declining every year. This is a cheerless oil supply picture with about 50 percent dependence expected on imported oil in the immediate future.

We know that gas production and gas reserves are declining. The American Petroleum Institute and American Gas Association recently reported that the remaining natural gas reserves declined by 12 trillion cubic feet during 1976 to a year-end level of 216 trillion cubic feet, the lowest in 22 years. The remaining gas reserve divided by 1976 gas production gives a future life of 11 years with over 10 percent of the remaining gas reserve at the Arctic Circle in Alaska and not connected. The trend of yearly gas production and yearly discoveries is shown on chart 2. The past production gas history and discoveries indicate that yearly discoveries of gas have not equaled production since 1962 in the lower 48 states.

Gas production in 1976 amounted to 19.5 trillion cubic feet, but discoveries were only 7.56 trillion cubic feet. The United States is particularly sensitive to the declining natural gas supplies. The importance of one trillion cubic feet of gas is better understood when you consider that it is equivalent to 170 million barrels of oil in heating value. The 1976 gas production was equivalent to 3.32 billion barrels of oil which, in energy value, exceeds the United States 1976 oil production of 2.8 billion barrels by 18.5 percent.

It should be pointed out that the estimated supply of natural gas is far below the demand and that there are serious curtailment problems now for the interstate gas pipelines because of gas shortages. During the period of Federal Power Commission gas price regulation the natural gas production for interstate sales has not kept pace with demand. FPC restrictions on gas prices below the finding and producing cost stopped new gas exploration and caused the present shortages. (Price regulation since 1954.) While deregulation would have driven up the price of natural gas, it would have expanded the gas supply. Today, the customers would not have to be relying on alternative substitute fuels in our nation at costs, in some cases, of over $1.00 to $5.00 per thousand cubic feet. Regulation of natural gas has penalized the consumer in all parts of the nation and has subjected the commercial and industrial users dependent upon interstate gas to costly shutdowns and increased fuel costs.

I surveyed the top 40 industrial users of oil and gas in the U.S. on January 6, 1977, and my conclusion from the responses is that it is necessary to "regulate" national gas prices on interstate sales, to equivalent cost of foreign oil, to make a meaningful step toward meeting interstate natural gas needs and not by raiding the limited supplies of intrastate gas for the interstate market. Congress, through your Ways and Means Committee, must get the facts in order to prepare a realistic U.S. energy program.

FACT NO. 2—LARGE POTENTIAL U.S. OIL AND GAS RESERVE FUTURE

The impact of our future oil and gas reserves on national energy policy is clear. Senator Henry M. Jackson, who chairs the Senate Interior Committee, has held many hearings on "how much oil and gas is left to find" stated recently before the Governors' conference on Monday, February 28, 1977, that the job of building a workable energy program must be based on the proposition (one of three) that "domestic production of oil and gas has peaked . . ."—Not so!, when we consider the excellent production possibilities from undrilled areas.

The record is clear from my studies, Exxon, Mobil/Moody, Hubbert, U.S. Geological Survey, Potential Gas Committee, and National Academy of Science that the onshore and offshore oil and gas potential is large under adequate oil and gas price incentives.

The oil discovery rate in the U.S. was decreased starting in the 1950's by cheap foreign oil. Domestic drilling started decreasing in 1956 because we could not find oil as cheaply as it could be purchased abroad. Foreign imports controlled the price of domestic oil until 1973 and slowed down domestic exploration activities. Then in 1973, we had U.S. government regulation of oil prices which has continued until today.

The oil and gas industry has been under price control for the last 25 years either by Federal Power Commission regulations, Federal Energy Administration regulations, or cheap foreign oil. There is no ideal exact geological scientific way of determining future petroleum hydrocarbon reserves from the multitude of undiscovered oil and gas reservoirs both onshore and offshore. My estimate is that the oil potential is over 100 billion barrels (35 times the 1976 oil production of 2.8 billion barrels) and that the gas potential is over 650 trillion cubic feet (33 times the 1976 gas production of 19.5 trillion cubic feet). The U.S. Geological Survey Study of 1975 confirms the magnitude of these estimates. Independent and major company geologists and exploration personnel have affirmed that the U.S. has a rich oil and gas potential. It should be pointed out that over the years, due to the low prices, 98 percent of the prospective sediments in the U.S. have remained untouched by drilling. These include the low productivity areas, deeper geologic basinal areas, frontier areas (remote from production) and special areas such as the offshore basins.

Oil and gas production has been established in only about 50,000 square miles (less than 2 percent) of the 3 million square miles identified as having potential. This does not consider the deeper possibilities within the 50,000 square miles.

We must take into consideration reliable future world price estimations that the world price will double in the next 15 years. Increased prices of oil and gas and better technology will increase potential reserves.

The correct answer for Congress is that we can rely upon a large potential oil and gas reserve with "regulated" new oil and gas prices at the world market prices. Senator Jackson has misinterpreted the reliability of the U.S. Geological Survey reserves by not taking into account how our depressed oil and gas prices for the last 25 years affected discovery rates.

FACT NO. 3—AVERAGE OIL AND GAS FINDING AND PRODUCING COSTS EXCEED $12.00 PER BARREL AND $2.00 PER THOUSAND CUBIC FEET

Higher oil and gas prices are required for new oil and gas. Recent finding and producing costs will exceed $12.00 per barrel for oil and $2.00 per thousand cubic feet for gas. Future finding and producing costs will increase but the exact finding cost cannot be estimated due to risk factors involved in oil and gas exploration. If oil and gas operators are to risk their capital for exploration, prices must be regulated at the world market prices and there can be no new taxes imposed. Taxes generated from U.S. labor and industry to produce the new oil and gas discovered will add a great amount to the Federal income.

FACT NO. 4—"REGULATION" OF NEW PRICE OF INTERSTATE NATURAL GAS AT THE MARKET PRICE DETERMINED BY WORLD OIL PRICE DOES NOT INCLUDE CHANGING THE FPC PRICE OF PRESENT SALES OF NATURAL GAS TO INTERSTATE PIPELINES

Old and present gas prices to interestate pipelines would not be altered and would continue to flow to interstate markets at prices far below present day replacement. The following gas prices by companies, based on 1975 sales price, would continue in effect.

SALES OF NATURAL GAS TO INTERSTATE PIPELINES BY MAJOR COMPANIES, 1975

	Sales volume (billion cubic feet)	Revenues (in millions of dollars)	Average price (cents per thousand cubic feet)
Exxon	964.8	305.3	31.65
Standard of Indiana	621.8	203.6	32.74
Texaco	608.1	215.9	35.51
Gulf	568.9	146.6	25.77
Mobil	429.4	182.7	33.86
Shell	491.1	166.2	33.84
Phillips	482.7	148.8	30.82
Union Oil of California	426.4	148.5	34.84
Atlantic Richfield	403.3	120.2	29.87
Standard of California	349.4	121.2	34.68
Cities Service	336.6	95.6	28.42
Sun Oil	282.7	118.2	41.79
Continental Oil	236.5	76.1	32.18
Superior Oil	196.1	71.4	36.44
Getty	195.4	66.3	33.95
Skelly	180.3	75.1	41.68
Pennzoil	140.7	66.9	47.53
Pennzoil Offshore	123.1	55.0	44.72
Marathon	79.8	28.2	35.39
Amerada Hess	42.2	19.0	35.54
Sohio	24.4	9.8	40.27
Mesa Petroleum	21.1	8.7	41.44
Hamilton Bros. Oil Co	16.2	8.6	53.25
Helmerich & Payne	14.2	2.5	17.84

"Regulation" of new gas at the world market prices would allow the interstate market to get additional gas to meet their demand requirements and ease the curtailment burdens. Overall interstate gas prices would increase at a slow rate. However, the total cost to the consumer would be less than using alternative fuels such as foreign oil, synthetic gas, liquefied natural gas, propane, etc.

In conclusion I wish to point out to your Committee the advantages of utilizing new domestic oil and gas versus purchasing of foreign oil.

Utilizing "Regulated" New Domestic Oil at World Price. Sweet Crude Oil at $15.41 per barrel. Sout Crude Oil at $13.10 per barrel.	Purchasing Foreign Oil at World Price. Sweet Nigerian Crude Oil at $15.41 per barrel. Sour Arabian Light Crude at $13.10 per barrel. Sour Iranian Light Crude at $13.91 per barrel.
ADVANTAGE	**DISADVANTAGES**
1. Would reduce our negative balance of payments for foreign oil and increase National Security with less dependence on insecure foreign oil.	1. Would increase our balance of payment deficits for foreign oil and decrease National Security.
2. With world price incentive at the end of 4 years, domestic oil production would increase over 2 million barrels of oil per day, or 730 million per year.	2. Would increase foreign oil purchase by 2 million barrels per day at a yearly cost of $10 billion to consumers and increase balance of payment difficulties.
3. Would use U.S. labor and would provide domestic oil for U.S. industries.	3. Would use no U.S. labor and be the probable cause of more unemployment.
4. Development of our domestic oil would generate work and business which would create additional Federal and State taxes.	4. Would create no additional taxes for U.S. Government by purchasing foreign oil.
5. Present U.S. energy consumption pattern of 75 percent use of oil and gas cannot be substantially changed in less than 4 or 5 years so that increased domestic oil supplies are needed until coal can replace a great portion of the U.S. supply.	5. Would increase out-of-pocket cost to consumers for a 4- to 5-year period until coal and other alternate fuels could be developed to replace part of the oil and gas. The total estimated cost of foreign oil for 1977 is $40 billion.

I want to thank you for the opportunity to appear before this hearing. I urge prompt action in stimulating development of new domestic oil and gas production. I will be happy to assist you in achieving enactment of this most important legislation for the consumers and producers of oil and gas in the United States.

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A CHRONOLOGICAL SEQUENCE OF PRICE REGULATION OF THE DOMESTIC OIL INDUSTRY FROM AUGUST 1973 TO MARCH 1977

August 1973—Cost of Living Council (CLC) Two-Tier Price System.

When domestic price controls were established, U.S. crude oil production averaged approximately 9.4 MMB/D, which was essentially all old oil for definitional purposes. Old oil was set at the May 14, 1973 posted price plus $0.35 per barrel totalling $4–4.25 per barrel. This represented an increase from $3.40 per barrel in early 1973.

A concept of new and released oil was introduced that permitted oil operators to sell certain incremental volumes of crude at market prices determined by OPEC. These prices approximated $5.00–5.25 per barrel.

The Cost of Living Council's crude price regulation program incorporated several important definitions. These included:

1. *Property*—a right that arises from a "Lease" or from "Fee Interest" to produce crude oil;
2. *Old Oil*—the number of barrels sold from a property in the corresponding month of 1972 or the number of barrels sold divided by 12;
3. *Base Production Control Level* (*BPCL*)—historic volume of crude produced and sold from a given property, above which a producer must increase the production level to qualify current production as "new" oil (old oil was assumed to decline volumetrically by 8% per year); and
4. *New, Released Oil*—volume produced and sold each month in excess of property's BPCL. (For every barrel of "new" crude produced and sold, one barrel of "old" crude was released for sale at OPEC prices, less applicable adjustment for volumetric rate declines in old fields that exceeded 8 percent per year.)

November 1973: Stripper oil (wells that produce 10 B/D or less) production was exempted from controls.

December 1973:

The Federal Energy Office was established.

New oil prices, which were unregulated and, in effect, established by OPEC, surged to $10 per barrel, while price-controlled old oil sold for $4–4.25.

The Cost of Living Council increased old oil prices by $1 per barrel to narrow the gap between old and new prices.

After the increase in old oil prices to $5 per barrel, the gap between old and new oil prices remained at about $5 per barrel versus $1 when the program began.

January 1974: The FEA issued Mandatory Petroleum Allocations and Price Regulations based on the mandate contained in the (EPAA) Emergency Petroleum Allocation Act. The pricing regulations followed CLC guidelines.

November 1974: The Entitlements Program (Old Oil Allocation Program) was initiated to equalize domestic refiners' crude costs.

December 1975: The Energy Policy and Conservation Act (EPCA) was enacted.

February 1976:

The EPCA stipulated the establishment of a nationwide statutory composite price mechanism. And the weighted average price of old oil and new, released and stripper oil was proposed to be set at $7.66 per barrel.

The FEA went on the assumption that upper-tier oil constituted 40% of domestic production and lower-tier represented 60% of total crude production. To arrive at the statutory price of $7.66 per barrel, upper-tier oil (formerly new, released, and stripper oil) prices were rolled back to an assumed price of $11.28 per barrel. Lower-tier prices were set at an assumed $5.25 per barrel.

TABLE VIII.—*FEA estimated upper-tier and lower-tier prices and volume mix—February 1976*

Estimated price and volume mix:	
Upper-tier price times percent mix	$11.28×0.40
Lower-tier price times percent mix	$5.25× .60
Weighted average statutory composite price	7.66

It was decided that the composite price would be allowed to increase by 3% annually (production incentive) plus inflation, but that the annual increase would not exceed 10%.

The EPCA program incorporated the following definitional change: 1. The BPCL would be calculated by the old method or *by the average monthly production and sale of old crude oil in 1975*. Existing cumulative deficiencies resulting from greater than expected production declines in older properties (used in determining the amount of crude included in the new and released category) were eliminated along with the released oil concept.

March 1976: The FEA increased the March to May quarterly prices at an annual rate of 9.8 percent. This assumed a 6.8 percent inflation rate and a 3 percent production incentive. The increase was to be applied equally (on a percentage basis) to both upper-tier and lower-tier production.

May 1976:

The FEA learned, via data collected from producers, that the actual mix between lower- and upper-tier crudes was 56:44, not the assumed 60.40; initial (February 1976) upper-tier prices were actually $11.47—not the estimated $11.28—and lower-tier prices were $5.06—not the estimated $5.25; the price deflator reported by the Government was only 3.5 percent rather than the 6.8 percent used as the estimated inflation adjustment.

The crux of the overcharging problem lay in the change in definition of the Base Production Control Level (BPCL), in December, 1975. The upper-tier/lower-tier mix (including stripper as upper tier) was upper-tier, 38.1 percent, lower-tier, 61.9 percent, in Dec. 1975. The FEA apparently felt that the BPCL definitional change would account for only a 2 point decline in the lower-tier percentage, but we estimate that it accounted for a 5.9 point decline, or approximately 3.9 points more than what the FEA had estimated. Had the FEA's estimate of the amount of oil that was shifted to the upper-tier category been accurate (based on a 60:40 split and an $11.47 and $5.06 price), the actual composite price would have been $7.62, or $0.04 per barrel less than the $7.66 statutory composite. Because of the shift of the *additional* 3.9 points (approximately 0.32 MMB/D) that resulted from the BPCL change, the average price was $7.87. Thus, the greater-than-expected transfer to the upper-tier increased the statutory composite price by $0.25 per barrel.

TABLE IX.—IMPACT OF BPCL DEFINITIONAL CHANGE ON FEBRUARY 1976 STATUTORY COMPOSITE PRICE—INCLUDING STRIPPER PRODUCTION

	Upper tier price times percent mix	Lower tier price times percent mix	Weighted average composite price
Estimated price and volume mix	\$11.28×.40	\$5.25×.60	\$7.66
Actual results	11.48×.44	5.07×.56	7.87
Results if FEA estimate of shift in production from lower tier to upper tier category is accurate	11.47×.40	5.06×.60	7.62

July 1976: To compensate for the overcharges, the FEA froze crude prices at June 1976 levels. Rather than rolling back prices, the agency opted to freeze prices in order to evaluate additional volume and composite price data. This was significant because the overcharges resulted from a greater-than-expected amount of old oil being shifted to the higher-priced upper-tier category.

August 1976 through September 1976:

The Energy Conservation and Production Act was enacted and its implementation resulted in the following:

1. The removal of the 3 percent limitation on the production incentive. Composite price increases, however, were still limited to 10 percent per year, but no longer were constrained if the annual inflation rate dipped below 7 percent; this additional incentive was intended to provide the FEA with a further means of encouraging domestic production, *particularly through the application of enhanced recovery techniques and the correction of gravity differential problems.*

2. Stripper well prices were once again exempted from controls but were included in the calculation of the statutory composite at imputed upper-tier prices. (This was done in order to prevent other prices in the lower 48 states from increasing by more than 10 percent per year.)

Definitional changes were:

1. The qualification period for stripper wells was changed from average production in the preceding calendar year to production in any consecutive 12-month period beginning after December 31, 1972, resulting in an increase in qualifications for stripper status. Additionally, once a well qualified as a stripper well, its status was permanently maintained even if stimulation programs increased production above 10 B/D per well in future years.

2. According to the FEA's Report to Congress, the concept that a property was defined as a single oil and gas lease, . . . "without regard to the separate reservoirs which might underlie the property, did not provide appropriate incentives under the longer-term system of price controls mandated by EPCA. This was because increased production from one reservoir might fail to qualify as upper-tier crude oil because of the requirement that total production from the property must exceed the BUCL and cumulative deficiency determined from all reservoirs, which underlie the property (the released oil problem) . . . Accordingly, the definition of property was amended, effective September 1, 1976, to permit a producer to treat as a separate producing property each separate producing reservoir subject to the same right to produce crude oil, provided that the reservoir is recognized as separate and distinct by the appropriate governmental regulatory authority. Although this change was not required in order to implement the EPCA or ECPA, it had been under consideration by FEA for sometime."

October 1976: Following the priorities established in the EPCA enacted in August, 1976, the FEA adjusted heavy old-oil prices in California and Alaska. In September, 1976, production of heavy oil in California (20° API average gravity) averaged 0.560 MMZ/D while southern Alaska production 35° API average gravity) averaged 0.160 MMB/D. For September, 1976, California crudes (ex. Elk Hills) were 69 percent lower tier, while Alaskan production was 83 percent lower tier. The FEA allowed the ceiling prices for these crudes to increase by 1) $0.02/barrel between 34° API and 40° API, and 2) $0.03/barrel per degree below 34° API. While this amendment increased the ceiling price of these crudes, the entitlement penalty for lower-tier oil and other market forces precluded any actual increase in price. In order to rectify the situation, the FEA proposed granting heavy Californian and Alaskan crudes a conditional entitlement to enable those heavy oil prices to increase. If the price increases are initiated, California crudes would increase by an average of $0.54 per barrel and Alaskan crudes by $0.10 per barrel. The net impact would be an increase in the statutory composite price of $0.035 cents per barrel, and an increase in the composite lower-tier price of approximately $0.08 per barrel.

January to March 1977:

The changes in definition of a producing property and stripper well qualification increased the statutory composite price by an estimated $0.32 per barrel between August and December 1976, thus accelerating the overcharges. In order to bring actual prices in line with the statutory composite price, the FEA rolled back upper-tier prices by $0.65 per barrel in two stages, and froze all prices until July 31, 1977. As a precautionary measure the Agency decided to continue the price freeze for one month longer than it estimated was necessary to maintain parity with the statutory composite. Also, FEA indicated that it planned to resume monthly price increases gradually, rather than as a one-shot adjustment to compensate for prices which had been held below the statutory composite. (Prices have been held below the statutory composite because of recent price rollbacks and price freezes.) In addition, the FEA currently intends to maintain a "bank" of deficit receipts, which may be useful in compensating for any future misestimations, in connection with compliance with the statutory composite price. If our analysis of the new property definition and its impact on production is accurate, the FEA may need some of this "bank." It is interesting that the FEA opted to roll back upper-tier prices by $0.65 per barrel while leaving the lower-tier price unchanged. Also, it is particularly noteworthy that the EPCA-mandated change in the definition of the Base Control Production Level (enacted in February) and the ECPA-mandated change in definition of a producing property (enacted in September) *increased the composite price by a total of $0.57 per barrel in 1976, according to our estimate. It is perhaps even more significant that this latest decision to roll back upper-tier prices and leave lower-tier prices untouched was made by the new leadership of the FEA, with the apparent consent of the Carter Administration. Thus, the expressed intent of both the Congressional and Executive branches has been to stimulate supply via incentives for older producing properties. The one flaw in the existing program, however, is that the retention of the $11.00 upper-tier price (in constant dollars) may not be adequate to compensate for the high cost and high risk inherent in frontier exploration.*

Hearings were held in the potential impact of tertiary recovery on U.S. production. The FEA has estimated that potential incremental production could range from 0.1–0.2 HHB/D in 1978 and 0.2–0.4 MMB/D in 1980. The FEA has categorized the following techniques as extraordinary and high cost enhancement technologies of a type associated with tertiary applications: miscible fluid or gas injection, chemical flooding, certain types of steam flooding and cyclic steam injection (huff and puff), fireflooding, microemulsion flooding, in situ combustion, polymer flooding, and related variations.

Hearings were held in March on the issue of the pricing of North Slope crude oil.

APPENDIX B

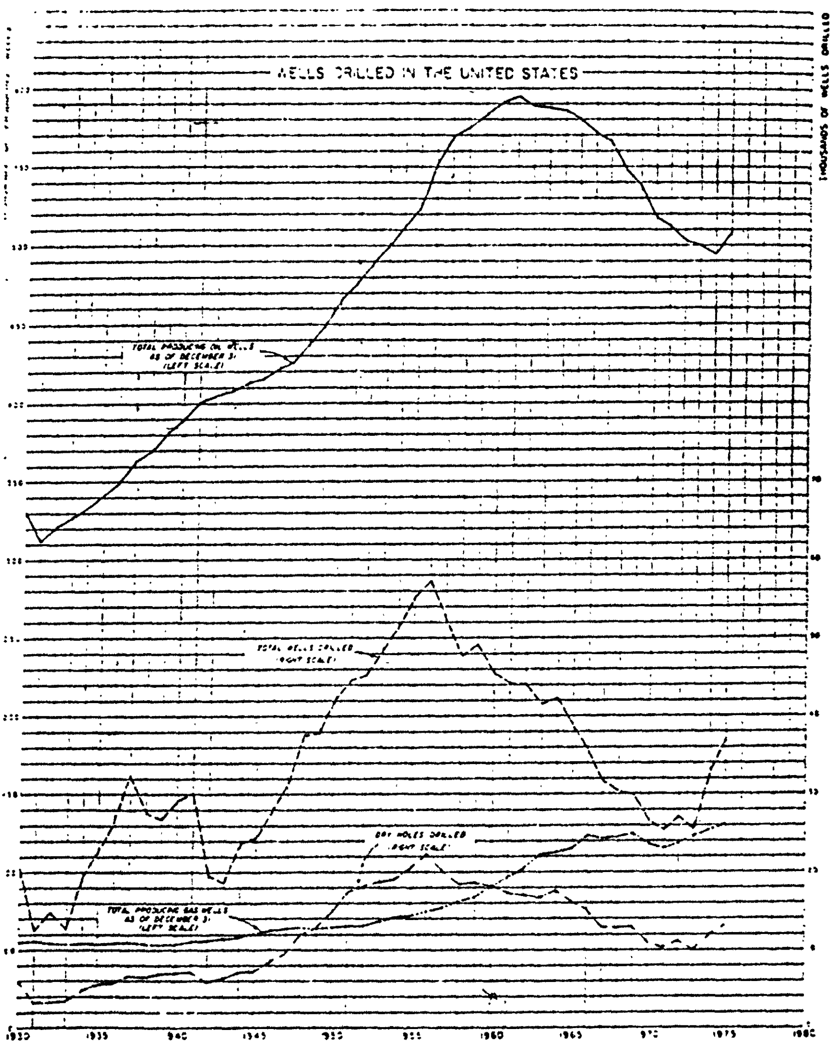
WELLS DRILLED IN UNITED STATES [1]

Year	Producing oil wells drilled	Condensate wells drilled	Gas wells drilled	Dry holes drilled	Total wells drilled	Producing wells, Dec. 31 — Oil	Producing wells, Dec. 31 — Gas
1918	17,860	----------	2,324	5,629	25,813	203,375	40,369
1919	21,041	----------	2,153	6,075	29,269	227,000	41,500
1920	24,278	----------	2,275	7,476	34,029	251,000	42,700
1921	14,715	----------	2,081	5,192	21,989	274,500	43,900
1922	17,790	----------	1,926	5,191	24,907	284,880	45,100
1923	16,182	----------	2,140	6,043	24,365	290,100	46,300
1924	14,702	----------	2,172	5,591	22,470	299,100	47,500
1925	17,029	----------	2,536	6,847	26,412	306,100	48,700
1926	18,626	----------	2,502	8,328	29,456	318,600	49,900
1927	14,382	----------	2,494	7,213	24,089	323,300	51,100
1928	12,348	----------	2,754	7,164	22,266	327,800	52,300
1929	15,362	----------	3,107	7,600	26,069	328,200	53,545
1930	11,693	----------	2,971	6,163	20,827	331,070	55,020
1931	7,011	----------	2,067	3,264	12,342	315,850	55,756
1932	10,530	----------	1,079	3,389	14,998	321,500	54,160
1933	8,070	----------	1,190	3,492	12,752	326,850	53,660
1934	13,119	----------	1,496	4,811	19,426	333,070	54,130
1935	15,418	----------	1,802	5,696	22,916	340,990	53,700
1936	18,704	----------	2,375	5,787	26,866	349,450	53,960
1937	23,115	----------	2,732	6,267	32,474	363,030	55,050
1938	19,106	----------	2,143	6,515	27,764	369,040	53,770
1939	17,734	----------	2,030	6,890	26,654	380,390	53,350
1940	19,843	----------	2,265	7,053	29,161	389,010	53,880
1941	19,590	----------	3,279	7,280	30,149	399,960	55,500
1942	10,977	105	2,685	5,962	19,729	404,840	56,150
1943	9,887	76	2,314	6,364	18,641	407,170	57,200
1944	13,502	54	3,024	7,153	23,733	412,220	58,780
1945	13,944	153	3,039	7,346	24,482	415,750	60,660
1946	16,087	207	3,355	8,496	28,145	421,460	62,740
1947	17,613	283	3,437	9,751	31,084	426,280	63,676
1948	22,197	346	2,966	11,939	37,448	437,860	64,212
1949	21,415	378	3,121	12,898	37,812	448,660	63,346
1950	23,775	465	3,015	14,918	42,173	465,870	64,900
1951	23,532	344	3,198	17,497	44,571	474,990	65,100
1952	23,371	348	3,345	18,211	45,275	488,520	65,450
1953	25,251	374	3,858	18,759	48,242	498,940	68,223
1954	28,063	672	3,547	19,137	51,419	511,200	70,192
1955	30,474	709	3,460	20,564	55,207	524,010	71,475
1956	30,641	551	3,944	22,254	57,390	551,170	74,261
1957	27,519	743	3,879	20,250	52,391	569,273	77,041
1958	24,311	710	4,319	18,421	47,761	574,905	80,400
1959	25,532	800	4,070	18,669	49,071	583,141	83,225
1960	22,258	764	4,385	18,212	45,619	591,158	90,761
1961	21,437	386	5,100	17,331	44,254	594,917	96,809
1962	21,727	297	5,056	17,078	44,158	588,280	102,545
1963	20,135	250	4,320	16,762	41,467	587,777	111,511
1964	19,905	276	4,418	17,694	42,293	585,255	112,899
1965	18,065	235	4,277	16,226	38,773	579,875	115,834
1966	16,216	203	4,118	15,193	35,730	570,930	124,092
1967	15,073	[2]	3,602	12,958	31,633	566,869	121,758
1968	13,982	[2]	3,329	12,954	30,265	548,331	123,528
1969	13,213	[2]	3,656	13,076	29,945	537,640	125,020
1970	12,398	[2]	3,225	11,161	26,784	517,177	118,864
1971	11,510	[2]	3,399	10,448	25,357	512,471	117,360
1972	11,139	[2]	4,777	11,171	27,087	503,505	119,167
1973	9,555	[2]	5,894	10,017	25,466	499,968	123,034
1974	13,719	[2]	7,032	11,867	32,618	494,352	126,997
1975	16,626	[2]	7,437	13,203	37,266	507,934	131,086

[1] Does not include water input, gas injection, and salt water disposal wells.
[2] Included in gas wells drilled.

Source: "World oil."

APPENDIX C



WELLS DRILLED IN THE UNITED STATES
THOUSANDS OF WELLS DRILLED
TOTAL PRODUCING OIL WELLS AS OF DECEMBER 31 (LEFT SCALE)
TOTAL WELLS DRILLED (RIGHT SCALE)
DRY HOLES DRILLED (RIGHT SCALE)
TOTAL PRODUCING GAS WELLS AS OF DECEMBER 31 (LEFT SCALE)
1930
1935
1940
1945
1950
1955
1960
1965
1970
1975
1980

APPENDIX D

INDEXES OF DOMESTIC PRODUCTION AND PROVED CRUDE RESERVES

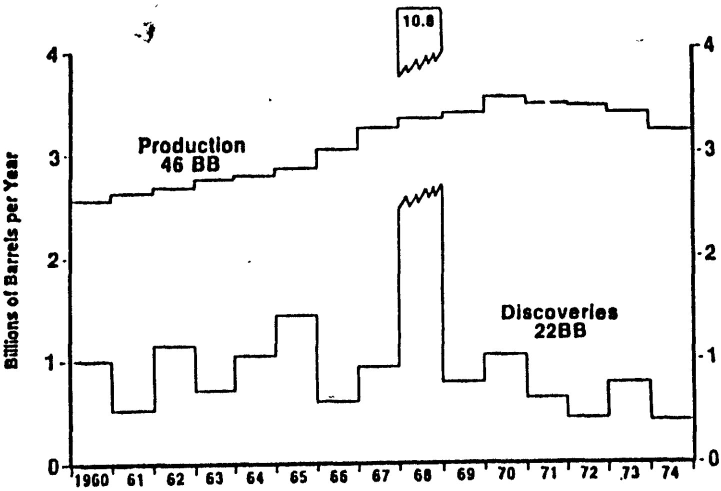
[Thousands of barrels]

Year	Domestic production: Total	Domestic production: Index (1926=100)	Proved reserves (end of year): Total reserves including condensate	Proved reserves (end of year): Index (1926=100)
1918	355,928	46.2	6,200,000	70.5
1919	378,367	49.0	6,700,000	76.1
1920	442,929	57.4	7,200,000	81.8
1921	472,183	61.3	7,800,000	88.6
1922	557,531	63.3	7,600,000	86.4
1923	732,407	95.0	7,600,000	86.4
1924	713,940	92.6	7,500,000	85.2
1925	763,743	99.1	8,500,000	96.6
1926	770,874	100.0	8,800,000	100.0
1927	901,029	116.9	10,500,000	119.3
1938	901,474	116.9	11,000,000	125.0
1929	1,007,323	130.7	13,200,000	150.0
1930	898,011	116.5	13,600,000	154.5
1931	851,081	110.4	13,000,000	147.7
1932	785,159	101.9	12,300,000	139.8
1933	905,656	117.5	12,000,000	136.4
1934	908,065	117.8	12,177,000	138.4
1935	996,596	129.3	12,400,000	140.9
1936	1,099,687	142.7	13,063,400	148.4
1937	1,277,664	165.7	15,507,268	176.2
1938	1,213,186	157.4	17,318,146	197.1
1939	1,261,256	164.0	18,483,012	210.0
1940	1,351,847	175.3	19,024,515	216.2
1941	1,404,182	182.1	19,589,296	222.6
1942	1,385,479	179.7	20,082,793	228.2
1943	1,503,427	195.0	20,061,152	228.4
1944	1,678,421	217.7	20,453,231	232.7
1945	1,736,717	225.2	20,826,813	236.0
			Reserves of crude oil only	
1945	1,736,717	225.2	19,941,846	226.6
1946	1,726,348	223.9	20,873,560	237.2
1947	1,850,445	240.0	21,487,685	244.2
1948	2,002,448	259.8	23,280,444	264.6
1949	1,818,800	235.9	24,649,489	280.1
1950	1,943,776	252.1	25,268,398	287.1
1951	2,214,321	287.2	27,468,031	312.1
1952	2,256,765	292.8	27,960,554	317.7
1953	2,311,856	299.9	28,944,825	328.9
1954	2,257,119	292.8	29,560,746	335.9
1955	2,419,300	313.8	30,012,170	341.0
1956	2,551,857	331.0	30,434,649	345.8
1957	2,559,044	332.0	30,300,405	344.3
1958	2,372,730	307.8	30,535,917	347.0
1959	2,483,315	322.1	31,719,347	360.4
1960	2,471,464	320.6	31,613,211	359.2
1961	2,512,273	325.9	31,758,505	360.9
1962	2,550,178	330.8	31,389,223	356.7
1963	2,593,343	336.4	30,969,990	351.9
1964	2,644,247	343.0	30,990,510	352.2
1965	2,686,198	348.5	31,352,391	356.3
1966	2,864,242	371.6	31,452,127	357.4
1967	3,037,579	394.0	21,376,670	356.6
1968	3,124,188	405.3	30,707,117	348.9
1969	3,195,291	414.5	29,631,862	336.7
1970	3,319,445	430.6	39,001,335	443.2
1971	3,256,110	422.4	38,062,957	432.5
1972	3,281,397	425.7	36,339,408	412.9
1973	3,185,400	413.2	35,299,839	401.1
1974	3,043,456	394.8	34,249,956	389.2
1975	2,886,292	374.4	32,682,127	371.4

Source: American Petroleum Institute.

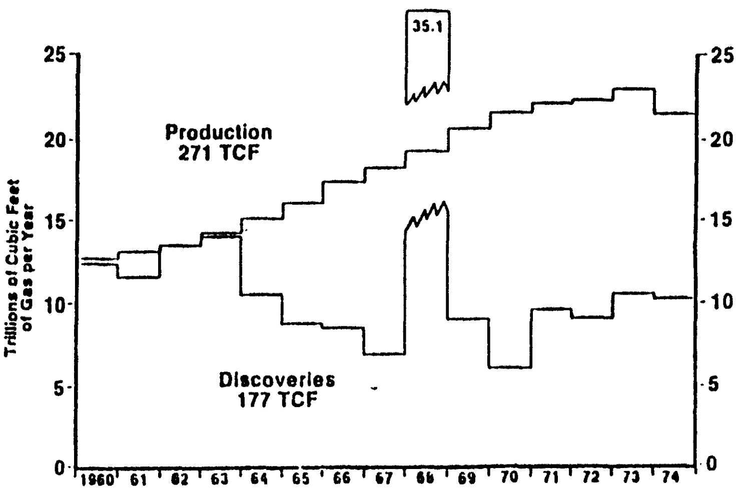
APPENDIX E

United States Oil Situation



APPENDIX F

United States Gas Situation



The CHAIRMAN. Next, we will hear from Mr. M. J. Mighdoll, executive vice president, National Association of Recycling Industries, accompanied by Mr. Edward Merrigan, counsel, National Association of Recycling Industries.

We appreciate having you before our committee, Mr. Mighdoll, and the fine work that is being done by you and your association to make better use of energy, particularly by making better use of what we have. We will welcome your statement.

STATEMENT OF M. J. MIGHDOLL, EXECUTIVE VICE PRESIDENT, NATIONAL ASSOCIATION OF RECYCLING INDUSTRIES, INC., ACCOMPANIED BY EDWARD MERRIGAN, COUNSEL, NATIONAL ASSOCIATION OF RECYCLING INDUSTRIES, INC.

Mr. MIGHDOLL. Thank you, Mr. Chairman. We appreciate the opportunity you have afforded us to represent the views of the recycling industry before this committee today. The purpose of our appearance, Mr. Chairman, is twofold.

First, we urge the committee to approve that portion of H.R. 8444, the House-passed energy legislation, which extends the increased energy investment tax credit to machinery and equipment installed by taxpayers to collect, process, and utilize energy-saving recyclable materials in industrial manufacturing operations.

That provision was approved by the Ways and Means Committee, the House Ad Hoc Energy Committee and the House itself without objection. It was also approved, in slightly different form, last year by the Senate Finance Committee. And, during the proceedings this year before the Ways and Means Committee, this increased energy investment tax credit for recycling equipment was supported by both the Treasury Department and the President's energy advisors. Clearly, this modest, long overdue energy conservation tax incentive should be enacted into law without further delay.

We also wish to urge the committee to enact, in cooperation with the Senate Commerce, Science, and Transportation Committee, a legislative solution to an extremely serious transportation problem which has historically precluded maximum industrial resource recycling and energy conservation in the United States. I will discuss that problem, and the proposed legislative solution, in further detail in just a moment.

The reason it is imperative for this committee to take these actions is perhaps best demonstrated by the energy conservation chart attached to this statement as exhibit A. It shows that, in 1976, the metals, paper, and rubber industries alone—all designated by the Federal Energy Administration as among the Nation's top 10 major energy-consuming industries—conserved the energy equivalent of 151,563,000 barrels of oil by simply using recyclable materials in their manufacturing operations in place of virgin natural resource counterparts—and in the process, they also one, conserved scarce natural resources and two, reduced air pollution by 86 percent and three, reduced water pollution by 76 percent.

American industry, however, has merely "scratched the recycling surface." Industrial recycling percentages have remained relatively dormant for years and, in most cases, they have substantially declined since World War II. Congress has understandably been deeply concerned with the problem. Just last year, the House Committee on Science and Technology stated in its report in support of the Resource Conservation and Recovery Act: "Only about 20 percent of paper is recycled; only about 8 percent of postconsumer and commercial ferrous metal is recycled, and only about 1 percent of aluminum. There is very little recycling of other metals from the postconsumer solid waste stream although there is some recovery from industrial scrap."

Accordingly, over the years since 1965, Congress has enacted a series of laws aimed at attaining maximum industrial recycling levels in the United States and at eliminating all shortsighted, federally sponsored economic roadblocks to maximum recycling.

Finally, just last week, when the House of Representatives passed the National Energy Act, it included a new provision in title II entitled "Use of Recovered Materials" which directs the Federal Energy Administration to establish targets for increased industrial recycling in the United States in the next decade—the purpose being to persuade American industry to try to double its current, extremely low, recycling levels and in the process increase industrial energy conservation by as much as 1 million barrels of oil a day by 1987.

Accordingly, the increased energy investment tax credit also contained in H.R. 8444 passed by the House last week—and which we support before this committee today—is intended to provide the metals, paper, textile, and rubber industries with an incentive to expand existing recycling plants and equipment and to invest in new recycling facilities designed to collect, process, and utilize energy-saving recyclable materials recovered from solid waste—and thereby endeavor to meet the new energy conservation targets for increased industrial recycling established by the Federal Government under the other provisions of H.R. 8444 I just described.

These two House-approved recycling provisions are just the opposite. They deal effectively with the need to conserve industrial energy through increased recycling—and they also deal, perhaps in advance for a change, with the following additional matters of tremendous national concern:

One, the need to conserve our Nation's depleting supplies of scarce virgin natural resources.

Two, the need to alleviate solid waste disposal costs and problems for cities and States throughout the Nation.

Three, the need to reduce industrial air and water pollution.

Four, the need to reduce our reliance on foreign sources and foreign cartels for our essential raw material supplies.

Five, the need to alleviate growing deficits in our balance of payments.

Increased industrial recycling is one important answer to all of those matters of crucial national concern, so the Senate clearly should adopt the two House-approved recycling provisions I just discussed.

But, if the Federal Government is to establish targets for increased industrial recycling and if American industry is to meet those goals and double its current recycling levels, one additional important step must be taken by the Congress: Unreasonable, discriminatory freight rates, which prevent free movement of recyclable metals, wastepaper, textiles, and rubber from collection points and municipal resource recovery centers to industrial mills where they can be utilized, must be rectified.

The time alloted for this testimony today does not permit me to discuss this problem in detail. However, approximately 10 days ago, I testified before the Senate Surface Transportation Subcommittee on this subject, and with your permission, Mr. Chairman, I would like to file a copy of that testimony with this committee for inclusion in the record at this point.

The CHAIRMAN. Without objection, agreed.

Mr. MIGHDOLL. In sum and substance, we urge the Senate Finance Committee to include any necessary tax aspects of the legislative solution required to remove this debilitating national transportation roadblock in the energy tax legislation now before the committee for consideration.

Considering the vital importance of this transportation problem to industrial energy and resource conservation and the urgent need to settle it fairly for the recycling industry and the railroads without further delay, we hope this committee and the Senate Commerce, Science, and Transportation Committee will cooperate and arrive at a legislative solution that can be sent to the President as part of the national energy program.

The national goal is to conserve 1 million barrels of oil per day through maximum industrial recycling. To reach that goal, the energy investment tax credit contained in H.R. 8444 is vitally necessary, and removal of malingering, unreasonable transportation rate barriers is absolutely essential.

Thank you, Mr. Chairman.

The CHAIRMAN. I agree that the discrimination against recycled materials does exist, and I would like to see the railroads eliminate it. The logical way for them to do it is for them to adjust their rates so that they charge a little more for the virgin materials and charge less for the recycled material. That is the logical way to do it, is it not?

Mr. MIGHDOLL. It would be, sir.

The CHAIRMAN. So far, we simply have not been able to get them to agree to that, as a practical matter. It does make sense.

I can assure you that whatever I can do to encourage them along that line, I will do. We will have the railroad people here, I assume, before this measure is disposed of, and I will raise that question with the railroad industry when they appear. I am sure that their representatives will be on notice that they are going to be asked about that matter when they appear before the Finance Committee.

Of course, the matter is under the jurisdiction of the Commerce Committee, of which I am a member, and where I am chairman of the Service Transportation Subcommittee, and I will raise the question there with them, too. It does seem to me that one step toward solving this problem is the kind of rate schedule that you suggest, to equalize the freight rates so you are not clobbered with a needlessly high freight rate to transport recycled material to the point where it can be used.

How much additional energy savings do you think can be achieved if the proposals that you advocate are implemented?

Mr. MIGHDOLL. Conservatively, sir, 50 percent in the next 5 years. We see a doubling in most commodities; therefore, double energy savings, during the next 10 years.

The CHAIRMAN. I am advised by our staff that they challenge some of the savings you are claiming. I would think that your members ought to work with the staff of our Committee to see if they can come together on a figure that they think they can agree upon as the precise amount of energy savings that we would have from recyclers. If the figure that you have in your survey is correct, it would mean that recycling is saving the equivalent of 25 days of oil imports with what industry is doing right now. That is the way I read it.

Mr. MIGHDOLL. I would like to point out that exhibit A is based on Federal Government data. Those are not our figures. We merely put together in one chart that data that has been accumulated by EPA and the Atomic Energy Commission and other agencies.

The CHAIRMAN. I am not saying that the figures you have are not agreed upon by the Government. All I am saying is that there are some people on the Joint Committee staff, and the Treasury staff, I suspect, who do not buy the conclusions suggested by those figures. I am not saying that you are saying anything wrong. I would be inclined to go along with you, but just the fact that when people say they disagree over the energy saving figures causes a problem. As the saying goes, figures do not lie, but liars can figure. There can be an honest difference of opinion as to what the conclusion is, or logically should be, as a result of the assumptions that are used.

I would hope that during the recess an effort will be made to try to come to a better agreement with the Joint Committee staff and the executive branch staff working in this area on the amount of energy savings that we could project if we encourage more recycling.

There is no doubt, the more recycling occurs, the more energy is saved, the better use can be made of materials. No one can argue about that, or the result of a cleaner environment.

Mr. MIGHDOLL. That is right, sir.

The CHAIRMAN. Thank you very much.

Any questions, Senator Packwood?

Senator PACKWOOD. No questions.

The CHAIRMAN. Thank you.

[The prepared statement and attachment of Mr. Mighdoll follow. Oral testimony continues on p. 398.]

STATEMENT OF NATIONAL ASSOCIATION OF RECYCLING INDUSTRIES, INC.

MR. CHAIRMAN: My name is M. J. Mighdoll. I am Executive Vice President of the National Association of Recycling Industries, Inc., 300 Madison Avenue, New York City, and I appear here today with the Association's counsel, Edward L. Merrigan of Washington, D.C. We appreciate the opportunity the Committee has afforded for the presentation of this testimony, and we shall endeavor to be as brief as possible.

The National Association of Recycling Industries (NARI) is the national trade association for the nonferrous metal,[1] wastepaper, textile and rubber recycling

[1] Recyclable aluminum copper, lead, zinc and other nonferrous metals.

industries. Our membership consists of more than 800 firms located throughout the United States, all of which are engaged in the industrial recycling of nonferrous metals, wastepaper, textiles and rubber—and in the management of municipal solid waste recovery systems such as the one recently constructed and now in operation in the City of New Orleans.

The purpose of our appearance, Mr. Chairman, is twofold:

1. We urge the Committee to approve that portion of H.R. 8444, the House-passed energy legislation, which extends the increased energy investment tax credit to machinery and equipment installed by taxpayers to collect, process and utilize energy-saving recyclable materials in industrial manufacturing operations. That provision was approved by the Ways and Means Committee, the House Ad Hoc Energy Committee and the House itself without objection. It was also approved, in slightly different form, last year by the Senate Finance Committee.[3] And, during the proceedings this year before the Ways and Means Committee, this increased energy investment tax credit for recycling equipment was supported by both the Treasury Department and the President's energy advisors. Clearly, this modest, long overdue energy conservation tax incentive should be enacted into law without further delay.

2. We also wish to urge the Committee to enact, in cooperation with the Senate Commerce, Science and Transportation Committee, a legislative solution to an extremely serious transportation problem which has historically precluded maximum industrial resource recycling and energy conservation in the United States. I will discuss that problem, and the proposed legislative solution, in further detail in just a moment.

The reason it is imperative for this Committee to take these actions is perhaps best demonstrated by the energy conservation chart attached to this Statement as exhibit A. It shows that, in 1976, the metals, paper and rubber industries alone—all designated by the Federal Energy Administration as among the nation's top 10 major energy-consuming industries—conserved the energy equivalent of 151,563,000 barrels of oil by simply using recyclable materials in their manufacturing operations in place of virgin natural resource counterparts—and in the process, they also (1) conserved scarce natural resources, (2) reduced air pollution by 86 percent and (3) reduced water pollution by 76 percent.

American industry, however, has merely "scratched the recycling surface". Industrial recycling percentages have remained relatively dormant for years, and in most cases, they have substantially declined since World War II. Congress has understandably been deeply concerned with the problem. Just last year, the House Committee on Science and Technology stated in its report in support of the Resource Conservation and Recovery Act:

"Only about 20 percent of paper is recycled; only about 8 percent of post-consumer and commercial ferrous metal is recycled, and only about 1 percent of aluminum. There is very little recycling of other metals from the post-consumer solid waste stream although there is some recovery from industrial scrap."

Accordingly, over the years since 1965, Congress has enacted a series of laws aimed at attaining maximum industrial recycling levels in the United States and at eliminating all short-sighted, federally-sponsored economic roadblocks to maximum recycling. In 1965, Congress passed the Solid Waste Disposal Act (42 U.S.C. 2151 et seq.). It directed the Environmental Protection Agency to investigate the effects of existing Federal programs and policies on industrial recycling and to recommend what might be done to eliminate all federally-sponsored disincentives to the reuse, recycling and conservation of materials (42 U.S.C. 3253a(a)(5), (6)).

In 1970, Congress passed two additional statutes—the National Environmental Policy Act (42 U.S.C. et seq.) and the National Materials Policy Act (Public Law 91-512. §§ 201-206). The former (NEPA) directed all agencies of the Federal Government "to use all practicable means . . . to enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources" (42 U.S.C. 4331). The second statute created the National Materials Policy Commission, and directed it to develop a "national policy" that would increase the "reuse of materials which are susceptible to recycling . . . in order to enhance environmental quality and conserve materials".

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[3] In the Energy Tax Section of the Tax Reform Act of 1976, the Finance Committee approved a 12 percent investment credit for recycling equipment. The House provision, with Treasury support, has approved a 20 percent credit for "energy property" such as recycling equipment.

In 1976, Congress enacted another statute—the Resource Conservation and Recovery Act (42 U.S.C. 6901 et seq.)—the purpose of which, among other things, is "to establish a cooperative effort among Federal, State and local governments and private enterprise in order to recover valuable materials and energy from solid waste" (42 U.S.C. 6902(8)); and to direct the Secretary of Commerce to deal effectively with all "economic and technical barriers to the use of recovered materials", and to "encourage development of new uses for recovered materials" (42 U.S.C. 6951–6953). The 1976 legislation also established a Resource Conservation Committee, to be comprised of most top-level Cabinet officers, to oversee the elimination of all existing disincentives to maximum resource recovery and conservation (42 U.S.C. 6982(j)).

Finally, just last week, when the House of Representatives passed the National Energy Act, it included a new provision in Title II entitled "Use of Recovered Materials" which directs the Federal Energy Administration to establish targets for increased industrial recycling in the United States in the next decade—the purpose being to persuade American industry to try to double its current, extremely low recycling levels and in the process increase industrial energy conservation by as much as 1 million barrels of oil a day by 1987.

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Certain provisions contained in the President's Energy Program have been criticized because they seem to deal belatedly with energy problems that were ignored or mismanaged for so many decades they are no longer susceptible to an effective legislative solution. But, these two House-approved recycling provisions are just the opposite. They deal effectively with the need to conserve industrial energy through increased recycling—and they also deal, perhaps in advance for a change, with the following additional matters of tremendous national concern:

1. The need to conserve our nation's depleting supplies of scarce virgin natural resources.
2. The need to alleviate solid waste disposal costs and problems for cities and states throughout the nation.
3. The need to reduce industrial air and water pollution.
4. The need to reduce our reliance on foreign sources and foreign cartels for our essential raw materials supplies.
5. The need to alleviate growing deficits in our balance of payments.

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EXHIBIT A

ENERGY SAVINGS IN RECYCLING COMPARED WITH VIRGIN MATERIAL USE

	Tons recycled in 1976	Energy required to manufacture 1 ton from virgin material in kWh/ton	Energy required to manufacture 1 ton from recycled material in kWh/ton	Energy saving per ton by recycling in kWh/ton	Total annual energy saving in 1976 in kWh	Savings in 1976 equivalent barrels of crude oil
Aluminum	[1] 1,433,000	[2] 51,379	[2] 2,000	49,379	70,503,000,000	41,710,000
Copper	[1] 1,423,591	[2] 13,532	[2] 1,726	11,805	16,798,000,000	9,880,000
Zinc	[1,3] 179,416	[4] 5,770	[5] 2,300	3,470	622,573,000	366,000
Lead	[1] 670,000	[4] 2,550	[5] 935	1,615	1,082,000,000	636,000
Iron and steel	[6] 46,111,452	[2] 4,270	[2] 1,666	2,704	124,685,000,000	73,340,000
Paper	[7] 10,158,000	[8] 6,730	[8] 2,520	4,210	42,765,000,000	25,156,000
Rubber	[9] 125,000	[9] 9,150	[9] 2,680	6,470	808,750,000	475,000
Total					257,664,323,000	151,563,000

SOURCES OF DATA

[1] Bureau of Mines/U.S. Department of the Interior.
[2] Oak Ridge National Laboratory (report No. ORNL-NSF-EP-24).
[3] Zinc content.
[4] Battelle Memorial Institute report PB-245759, "Energy Use Patterns in Metallurgical and Nonmetallic Mineral Processing."
[5] Private communication from Arthur D. Little Corp.
[6] U.S. Bureau of Mines and Arthur D. Little Estimates. (Receipts are used rather than consumption as figures for consumption do not distinguish between home and purchased scrap.)
[7] U.S. Department of Commerce/Bureau of the Census.
[8] U.S. Environmental Protection Agency "Report to Congress," February 1973, p. 11, table 4 (converted from Btu to kWh using standard conversion of 1 kWh equals 3,413 Btu).
[9] Industry estimates.

NEW YORK, N.Y.

NATIONAL ASSOCIATION OF RECYCLING INDUSTRIES, INC., BEFORE THE SUBCOMMITTEE ON SURFACE TRANSPORTATION, SENATE COMMITTEE ON COMMERCE, SCIENCE AND TRANSPORTATION

OVERSIGHT HEARINGS ON THE RAILROAD REVITALIZATION AND REGULATORY REFORM ACT OF 1976

STATEMENT OF NATIONAL ASSOCIATION OF RECYCLING INDUSTRIES, INC.

MR. CHAIRMAN: My name is M. J. Mighdoll. I am Executive Vice President of the National Association of Recycling Industries, Inc., 330 Madison Avenue, New York City, and I appear here today with the Association's counsel, Edward L. Merrigan of Washington, D.C. We appreciate the opportunity the Committee has afforded for the presentation of this testimony, and we shall endeavor to be as brief as possible.

The National Association of Recycling Industries (NARI) is the national trade association for the nonferrous metal,[1] wastepaper, textile and rubber recycling industries. Our membership consists of more than 800 firms located throughout the United States, all of which are engaged in the industrial recycling of nonferrous metals, wastepaper, textiles and rubber.

My testimony, Mr. Chairman, concerns Section 204 of the Railroad Revitalization and Regulatory Reform Act of 1976 entitled "Investigation of Discriminatory Freight Rates for the Transportation of Recyclable Materials", and the unfortunate complete violation and defeat of the Congressional mandate contained in that section of the law by the Interstate Commerce Commission.

Since Section 204 originated in this Committee, you will recall that, for almost 10 years Congress and responsible federal, state and municipal agencies have

[1] Recyclable aluminum, copper, lead, zinc and other nonferrous metals.

repeatedly emphasized that industrial utilization of recyclable materials in place of their virgin natural resource counterparts results in—

(i) major energy savings for the United States—as much as 95 percent energy conservation in aluminum manufacturing, 60 percent in paper production and 70 percent in the copper industry;

(ii) conservation of scarce, depleting natural resources;

(iii) important reduction of industrial air pollution, water pollution and water utilization;

(iv) reduced U.S. dependence on foreign cartels for critically important natural resource raw materials;

(v) alleviation of bulging deficits in U.S. balance of payments resulting from increased reliance on foreign natural resources, and

(vi) relief to state and local governments in their constant struggle against the "solid waste disposal crisis" and rising solid waste disposal costs.

In 1976, for example, the metals, paper and rubber industries—all designated by the Federal Energy Administration as among the nation's top 10 major energy-consuming industries—conserved the energy equivalent of 151,563,000 barrels of oil by simply using recyclable materials in their manufacturing operations in place of competing virgin natural resource counterparts (See appendix A hereto), and in the process they reduced air pollution by as much as 86 percent and water pollution by as much as 76 percent.

American industry, however, has merely "scratched the recycling surface." Industrial recycling percentages have remained relatively dormant for years, and in most cases, they have substantially declined since World War II. Congress has understandably been deeply concerned with the problem. Just last year, the House Committee on Science and Technology stated in its report in support of the Resource Conservation and Recovery Act:

"Only about 20 percent of paper is recycled; only about 8 percent of post-consumer and commercial ferrous metal is recycled, and only about 1 percent of aluminum. There is very little recycling of other metals from the post-consumer solid waste stream although there is some recovery from industrial scrap."

Accordingly, over the years since 1965, Congress has enacted a series of laws aimed at attaining maximum industrial recycling levels in the United States and at eliminating all short-sighted, federally-sponsored economic roadblocks to maximum recycling. In 1965, Congress passed the Solid Waste Disposal Act (42 U.S.C. 3251 et seq.). It directed the Environmental Protection Agency to investigate the effects of existing federal programs and policies on industrial recycling and to recommend what might be done to eliminate all federally-sponsored disincentives to the reuse, recycling and conservation of materials (42 U.S.C. 3253a (a)(5), (6)).

In 1970, Congres passed two additional statutes—the National Environmental Policy Act (42 U.S.C. 4321 et seq.) and the National Materials Policy Act (Public Law 91-512, §§ 201-206). The former (NEPA) directed *all* agencies of the Federal Government "to use all practicable means . . . to enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources" (42 U.S.C. 4331). The second statute created the National Materials Policy Commission, and directed it to develop a "national policy" that would increase the "reuse of materials which are susceptible to recycling. . . in order to enhance environmental quality and conserve materials".

In 1976, Congress enacted another statute—the Resource Conservation and Recovery Act (42 U.S.C. 6901 et seq.)—the purpose of which, among other things, is "to establish a cooperative effort among Federal, State and local governments and private enterprise in order to recover valuable materials and energy from solid waste" (42 U.S.C. 6902(8)); and to direct the Secretary of Commerce to deal effectively with all "economic and technical barriers to the use of recovered materials", and to "encourage development of new uses for recovered materials" (42 U.S.C. 6951-6953). The 1976 legislation also established a Resource Conservation Committee, to be comprised of most top-level Cabinet officers, to oversee the elimination of all existing disincentives to maximum resource recovery and conservation (42 U.S.C. 6982(j)).

Finally, just last week, when the House Commerce Committee formally reported the President's National Energy Act, it included a new provision which directs the Federal Energy Administration to establish targets for the increase of industrial recycling in the United States in the next decade—the purpose being to persuade American industry to try to double its current, extremely low recycling levels and in the process increase industrial energy conservation by as much as 1 million barrels of oil a day.

Similarly, just last week, the House Ways and Means Committee reported the tax portion of the Energy Act, in which it designated industrial recycable materials as "energy property", and increased the investment tax credit for firms that install new machinery and equipment for the purpose of increasing industrial utilization of recyclable materials.

But, a major insurmountable roadblock to maximum industrial recycling in the United States still remains—solely because an arbitrary, capricious, shortsighted Interstate Commerce Commission has stubbornly refused to obey not one but two successive Congressional mandates to remove it. I refer, of course, to grossly unjust, unreasonable discriminatory railroad freight rates for recycable materials which prevent and impede the movement of those materials from collection points to industrial plants where they can be recycled.

In its 1973 Report to Congress under the Solid Waste Disposal Act, the Environmental Protection Agency stated:

"The economics of recycling are . . . influenced by apparently inequitable freight rates . . . which make the transportation of secondary materials relatively more costly than the movement of virgin materials."

And, in its 1973 Report to Congress under the National Materials Policy Act, the National Materials Policy Commission reported:

"Rail freight rates are an important factor in the economics of recycling. Transportation costs are a large percentage of the total cost of using some secondary materials. Often they determine whether recycling can be profitable. Certain railroad freight rates appear to discriminate against secondary materials in favor of virgin materials . . .

"As transportation costs increase with distance, the rates determine not only whether the scrap moves but also how far, in effect, transportation costs isolate many forms of scrap from various buyers. . . .

"Wastepaper and textile scrap sometimes cost processors less to acquire than to ship.

"The higher the cost of tranpsortation is relation to the final selling price, the less the processor can spend to upgrade scrap. Then only high quality scrap moves; the rest is solid waste."

The National Materials Policy Commission thus made the following recommendation to the President and the Congress:

"We recommend that the Federal Government take the necessary steps to correct the existing freight rate differentials between secondary and primary materials."

When Congress passed the Regional Rail Reorganization Act of 1974 (45 U.S.C. 701 et seq.), therefore, the following mandate to the Interstate Commerce Commission was included in Section 603 (45 U.S.C. 793):

"*Freight Rates For Recyclables*

The Commission shall, by expedited proceedings, adopt appropriate rules under the Interstate Commerce Act which will eliminate discrimination against the shipment of recyclable materials in rate structures and in other Commission practices where such discrimination exists."

The Interstate Commerce Commission capriciously responded to that statute by simply re-codifying its old existing rules and regulations with reference to rated discrimination which had enabled the outrageous discrimination against recyclables to thrive. The Commission took no action whatsoever to eliminate, reduce or modify any rate charged for the movement of those materials. On the contrary, the Commission seriously exacerbated the existing discrimination by approving, during the short period from 1974 to 1976, seven (7) successive new, cumulative rate increases for recyclable materials totaling 38.3 percent—or roughly $100 million a year—while, in the process, it actually allowed the railroads to exempt certain competing virgin natural resource materials from the same rate increases.

In the final analysis, therefore, the Commission arbitrarily and unlawfully responded to the 1974 Act to Congress by increasing transportation charges for shippers of recyclable materials by roughly $100 million per year!

This performance by the Commission led to the second clear, unambiguous

Congressional mandate to the Commission found in Section 204 of the Railroad Revitalization and Regulatory Reform Act of 1976. There are no "ifs", "ands" or "buts" about Section 204. It directed the Interstate Commerce Commission in plain, unmistakeable terms—

(1) to conduct an investigation of (a) the base rate structure for competing virgin natural resource materials and their recyclable counterparts and (b) the manner in which such rate structure has been affected by successive general rate increases approved by the Commission in recent years;

(2) to place the burden of proof on the railroads to establish that their rate structures, as effected by recent rate increases, are just, reasonable and nondiscriminatory;

(3) to remove, within one year, all portions of the rate structure, as eaffected by recent rate increases, which are either unjust, unreasonable or discriminatory;

(4) to report to the President and Congress all actions taken by the Commission to eliminate unreasonable or unjustly discriminatory rates for the transportation of recyclable materials.

The Commission conducted the prescribed investigation, but in all other respects it flatly violated and ignored the Congressional mandates of Section 204.

The short time allotted for this testimony makes it impossible for me to outline here all the devices the Commission employed to violate Section 204. If this Committee wants those details for the record, I shall be pleased to supply them. But, for the purposes of this hearing, it seems sufficient to state that only 8 ICC Commissioners participated in the decision of February 1, 1977 which defeated the Congressional mandates contained in Section 204—and only 5 of those 8 voted in favor of disobeying the law. The other 3, including the present Chairman of the Commission (Mr. O'Neal) and the Vice Chairman (Mr. Clapp), strenuously dissented—and what they said in their dissents adequately summarizes how the majority simply ignored and violated section 204.

In the first dissent, Commissioners O'Neal and Christian stated:

"I do not believe that the majority has complied with Section 204 of the 4R Act by issuing its report. Section 204(a)(2) requires the Commission to conduct an investigation of the rate structures of recyclable materials and competing virgin natural resource materials, in which the rail carriers bear the burden of proving that the rate structures are reasonable and nondiscriminatory. To me, this means that the entire burden of justifying the existing rate structures was placed on the railroads, who were obligated to demonstrate that such structures are reasonable and do not result in discrimination against recyclables. But under the majority's approach, this has not been done. The report dwells more on industry structures than rate structures and has unlawfully shifted the burden of proof to the ratepayers.

"The report never comes to grips with the concept of discrimination. In practical effect, the report has lifted the statutory burden of proof from the carriers and placed it on the shippers.

". . . The only inquiry appears to be 'what the traffic will bear'. There is no real analysis of rate structures. Nor is there any thorough analysis of the effect of the general increases upon those rate structures, which is required by Section 204.

"This agency has been promising, and under section 204 was required, to resolve the long-standing question of whether the underlying rate structures for virgin materials and competing recyclable material are unreasonable or discriminatory. The Supreme Court in *Aberdeen & Rockfish R. Co.* v. *S.C.R.A.P.*, 422 U.S. 289, 322–28 (1975), recognized our discretion to select an appropriate proceeding to examine the issue. This was supposed to be that proceeding. I am sorry to state that we have failed to resolve the issue by neglecting to abide by the rules provided by the Congress."

And, in a second, separate dissent, Vice Chairman Clapp stated:

"The majority, in approving this report, have failed to meet the Commission's responsibility under section 204 of the 4R Act. In essence Congress instructed the Commission to investigate the rate structure for "recyclable or recycled materials and competing natural resource materials, and the manner in which such rate structure has been affected by successive general rate increases". The Commission has responded in this report by saying the commodities do not compete. That misses the mark and by a wide margin.

"The record clearly demonstrates that rate disparities exist with regard to some of the recyclable commodities and their virgin counterparts. The investigation should have focused on the question of whether or not existing rate disparities are justified by a difference in transportation conditions. Instead, the Commission has applied a traditional Section 3(1) [of the Interstate Commerce Act] analysis, and has found that there is no competition between most of the commodities under investigation, and that shippers of recyclables are entitled to no relief.

"The concept of competition applied here is unrealistically narrow. . . ."

The Facts Presented By The Railroads Themselves Under Section 204 Of The 1976 Act Establish That Their Freight Rate Structures For Recyclable Nonferrous Metals, Wastepaper, Textiles And Rubber Are Clearly Unjust, Unreasonable And Discriminatory—And Thus They Should Be Eliminated Without Further Delay.

As strong as the last mentioned dissenting opinions are, they plainly did not go far enough. Indeed, the evidence the railroads themselves produced before the Commission in response to Section 204 of the 1976 Act established beyond peradventure that their rate structures for recyclable aluminum, copper, lead, zinc, wastepaper, textiles and rubber are extraordinarily unreasonable and discriminatory—and thus, in the national interest, they must be eliminated without further delay.

The record before the Commission, buttressed by detailed cross-examination of witnesses produced by the railroads and their virgin industry supporters, shows that, for decades, there has been a long-standing, close economic interrelationship between the railroads, on one hand, and certain large integrated corporations which produce and ship virgin natural resource materials by rail on the other.

Some of the larger railroads own vast timberlands and mines, and naturally they transport the virgin commodities they produce to market by rail. In many cases, they (the railroads) sell the virgin commodities they produce to large integrated corporations also engaged in the production and rail shipment of the same virgin materials. These large integrated corporate producers, in turn, own their own railroads—either directly or through corporate subsidiaries—and they utilize those railroads and connecting lines to ship their virgin materials either to their own mills or to market.

Accordingly, representatives of the railroads, including representatives of the railroads owned by large integrated virgin material poducers, sit together in the Eastern, Western and Southern Freight Associations, and establish the rates which govern the movement by rail of both their own virgin natural resource materials and competing recyclable materials.

It is hardly suprrising, therefore, that these close economic and operating relationships between the railroads and some of the nation's largest integrated producers of virgin raw materials have led to the following grossly unreasonable, flagrantly discriminatory practices, proof of which is on the record before the Commission.

1. The railroads carry huge volumes of virgin natural resource materials "below cost" (as much as 33 percent below cost), and thus effectively force shippers of competing recyclable materials, who are always required to pay rates that produce revenues far in excess of the railroads' costs, to subsidize the movement of cometing virgin materials.

2. Shippers of virgin materials have been permitted "to negotiate" rate scales and rate formulas not available to shippers of recyclable materials.

3. Shippers of virgin materials have been accorded attractive "incentive rates" not heretofore available to shippers of recyclable materials.

4. Shippers of virgin materials have been exempted from general rate increases the railroads and the Interstate Commerce Commission have forced shippers of recyclable materials to bear, albeit such rate increases simply aggravated an already grossly-discriminatory base rate structure.

5. Shippers of virgin materials have been favored with extremely low rates for movement of virgin materials based on "tie-in arrangements" or "back-haul arrangements" shippers of recyclable materials cannot obtain.

6. The railroads have spent millions of dollars in recent years to provide hundreds of new, special purpose cars to shippers of virgin materials—cars which can be used only for the movement of those virgin materials—albeit the transportation rates paid by those virgin shippers still provide revenues to the railroads which are substantially below the costs incurred by the railroads to provide that transportation.

Under a rate-fixing system such as that described above—wherein those possessed of huge economic stakes in virgin natural resource materials control the rate structures and the rate-increase procedures—the establishment of unfair, unreasonable, discriminatory rates for the transportation of competing recyclable counterparts of those same virgin natural resource materials has been constant and exceedingly oppressive.

Over the years, of course, the railroads have established hundreds of thousands of rates for the transportation of virgin and rec··lable materials throughout the United States. So how does the Commission determine whether rates generally, or a particular rate structure, are unfair, unreasonable, or discriminatory? It does so by examining the railroads' Revenue/Variable Cost Ratios applicable to the rate or rate structure under review.

Studies conducted by the Commission itself have determined, for example, that All Rail Traffic Carried By The Railroads Nationally moves at rates which produce, or the average, a Revenue/Variable Cost Ratio of 131.8 percent. In other words, on the average, the railroads collect revenues from shippers of all types of goods—from automobiles to grain to machinery etc.—which exceed the railroads' variable costs by 31.8 percent.

As this Committee knows, the Railroad Revitalization and Regulatory Reform Act also directed the Commission to establish a basis for determining whether the railroads have "market dominance" or "transportation monopoly" over particular traffic or particular commodities. Late last year, the Commission ruled that a presumption of "market dominance" exists under the 4R Act when the railroads' Revenue/Variable Cost Ratio for a particular commodity is 160 percent or higher. In other words, if the railroads' revenues exceed costs by 60 percent or more, a presumption of railroad dominance or monopoly over the movement of that commodity is in order.

Finally, late last year the Commission also ruled, in a case involving coal transportation, that a commodity of that nature, charged with a public interest as energy property, is entitled to a railroad rate structure which produces a Revenue/Variable Cost Ratio of 127 percent—i.e. below the national average for all traffic.

With that background, let's examine the Revenue/Variable Cost Ratio evidence the railroads themselves produced under Section 204 of the 4R Act. They are as follows:

[In percent]

Commodities	East	South	West
Recyclable aluminum residues	431	227	213
Recyclable aluminum scrap	177	184	161
Miscellaneous recyclable nonferrous metals	319		227
Recyclable copper scrap	191	211	226
Recyclable copper matte	204		281
Recyclable lead matte	156		171
Recyclable lead and zinc scrap	186	226	155
Recyclable zinc dross	179	214	151
Virgin pulpwood	67	97	103
Virgin wood chips	61		
Recyclable wastepaper	124	138	150
Recyclable textile waste	125	109	144
Recyclable rubber		228	241
Recyclable rubber waste	128	164	164

Plainly, if the railroads can afford to carry All Traffic in the United States at rates which produce an average Revenue/Cost Ratio of 131.8 percent—and if the Commission has determined that commodities charged with "a public interest" (such as coal) should be carried at rates that produce a Revenue/Cost Ratio

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of 127 percent—and if a Revenue/Cost Ratio of 160 percent connotes railroad dominance or monopoly over a commodity, the Congressional mandate contained in Section 204 of the 1976 Act surely demands that action must be taken immediately—without further debilitating delay—to reduce rates for most of the recyclables listed above to a point where they produce, at all times in the future, a maximum Revenue/Variable Cost Ratio of no more than 131.8 percent—e.g. the "national average" for all freight that moves by rail.

Recyclable wastepaper and textiles, of course, require a different solution—at least on a temporary basis. Since they compete with virgin materials (pulpwood and wood chips) which, for decades, have enjoyed "noncompensatory rate" levels ("below-cost" rates), the rates for those two recyclable materials must be reduced to "break-even" rate levels until the railroads take action to bring rates for the competing virgin materials up to the "break even" point. Then, rates for the competing virgin and recyclable paper-making materials should move together. In no case, of course, should the rates for recyclable wastepaper or textiles exceed the "national average" Revenue/Cost Ratio of 131.8 percent.

Nothing less than this will fairly respond to the Congressional mandate of Section 204, and to our nation's obvious urgent need to increase industrial recycling and conservation of critical energy and natural resources without further delay.

Two additional short comments seem necessary. First, the record before the Commission under Section 204 established that all recyclable materials our Association represents have extremely favorable transportation characteristics for the railroads. They move in General Purpose Boxcars, which are loaded by shippers and unloaded by consignees. The railroads do not have to furnish any special equipment to move the traffic, and they do not get involved in the loading or unloading. Modern technology allows shippers to move carload weights and volumes which are comparable to those of virgin material counterparts. In any event, since under the rate solution outlined above, the railroads will always receive more revenues (roughly 31.8 percent) than their costs to move these recyclables—in no case can anyone validly contend that higher rates are required because of the "transportation characteristics" of the traffic. The movement of recyclables will always produce a fair, reasonable Revenue/Cost Ratio for the railroads.

Secondly, it is clear that the unreasonable, discriminatory rate structure for recyclable nonferrous metals, wastepaper, textiles and rubber can be rectified without seriously reducing the railroads' revenues.

The railroads offered evidence before the Commission to show that their total freight revenues are currently as follows:

	Billion
Nationally	$18.84
Eastern Railroads	6.37
Southern Railroads	3.20
Western Railroads	9.27

The railroads also proved under Section 204 of the 4R Act that currently their revenues for recyclable nonferrous metals, wastepaper and textile traffic are as follows:

(i) Recyclable Nonferrous Metals

	Million
Nationally	$43.22
Eastern Railroads	14.51
Southern Railroads	7.63
Western Railroads	21.09

(ii) Recyclable Textiles

	Million
Nationally	$13.60
Eastern Railroads	4.86
Southern Railroads	5.39
Western Railroads	3.34

(iii) Recyclable Wastepaper

	Million
Nationally	$58.69
Eastern Railroads	21.23
Southern Railroads	14.47
Western Railroads	22.99

If rates for recyclable nonferrous metals are reduced to the national average Revenue/Cost Ratio of 131.8 percent by Congress or the Commission, the revenue losses for the railroads will be only—

	Million
Nationally	$17.00
Eastern Railroads	5.80
Southern Railroads	3.10
Western Railroads	8.10

If rates for recyclable wastepaper and textiles, in turn, are reduced to the fully compensatory "break-even" level, as urged above, the revenue losses for the railroads will be—

	Million
Nationally	$16.39
Eastern Railroads	3.69
Southern Railroads	4.53
Western Railroads	8.17

In sum total, therefore, these rate reductions for the above recyclables, which are so vitally necessary and imperative in the national interest, would amount to only $33.39 million nationally—a figure which is roughly ⅙ of 1 percent of the railroads' freight revenues of $18.84 billion a year.

And, of course, those revenues do not include the monies the railroads receive from the sale of virgin natural resources they mine and harvest from their own mining and timberland properties.

But clearly, the rate reductions necessary to bring justice to the unreasonable, debilitating rate structures presently preventing maximum industrial recycling in these commodities in the United States do not have to result in any net revenue losses to the railroads. Those rate reductions will lead to substantial increases in the volume of these recyclable commodities which can move by rail, and this will bring offsetting revenues to the railroads. Also, the railroads can actually gain revenues if they will act to make all traffic moving by rail pay compensatory rates—rates which at least cover all of the railroads' variable costs.

CONCLUSION

The time has certainly arrived for full, fair, effective elimination of all rates for the transportation of recyclable nonferrous metals, wastepaper, textiles and rubber which are unjust, unreasonable, or discriminatory. Section 204, in fact, directed the Commission to eliminate all unreasonable, discriminatory rates for these materials "within 1 year"—i.e. before February 5, 1977.

Six months have passed since February 5, 1977, and the recyclable materials for which I speak are still laboring under a completely unreasonable, discriminatory rate structure. Indeed, during 1976, the Commission actually approved 2 new rate increases for all recyclable materials while it was simultaneously violating Section 204. In other words, since Section 204 was passed, the Interstate Commerce Commission has added further insult to injury as far as recyclables are concerned, and has shown an inherent inability to comply with Congressional mandates or to take actions in energy and resource conservation areas which are urgently necessary and in the national interest.

Accordingly, we urge this Committee to adopt and report a fair legislative solution to this problem as part of the National Energy legislation presently before the Congress.

If American industry is to meet Energy Efficiency Targets and Resource Recovery and Conservation Targets established by the Federal Energy Administration under the Energy Policy and Conservation Act and the National Energy

Act presently before Congress—and if the United States is to save 1 million barrels of oil a day through maximum industrial recycling—rates for the movement of recyclable materials must be reduced from their present exceedingly unreasonable, discriminatory levels to the national average—that is, they must produce revenues for the railroads that do not exceed railroad costs by more than 32 percent. And, where specific virgin materials still travel at noncompensatory rate levels, rates for competing recyclable counterparts must be further reduced in the national interest.

As indicated above, these legislative actions should not result in any real loss of revenues for the railroads. But, if they do, then the legislation we propose would authorize the Secretary of Transportation to eliminate those losses by making comparable payments to the railroads out of energy taxes or energy conservation taxes collected under the new National Energy Program, because of course, the rate reductions are intended to produce maximum energy conservation for the United States.

APPENDIX A

ENERGY SAVINGS IN RECYCLING COMPARED WITH VIRGIN MATERIAL USE

	Tons recycled in 1976	Energy required to manufacture 1 ton from virgin material in kWh/ton	Energy required to manufacture 1 ton from recycled material in kWh/ton	Energy saving per ton by recycling in kWh/ton	Total annual energy saving in 1976 in kWh	Savings in 1976 equivalent barrels of crude oil
Aluminum	[1] 1,433,000	[2] 51,379	[2] 2,000	49,379	70,903,000,000	41,710,000
Copper	[1] 1,423,591	[2] 13,532	[2] 1,726	11,805	16,798,000,000	9,880,000
Zinc	[1 3] 179,416	[4] 5,770	[5] 2,300	3,470	622,573,000	366,000
Lead	[1] 670,000	[4] 2,550	[5] 935	1,615	1,082,000,000	636,000
Iron and steel	[6] 46,111,452	[2] 4,270	[2] 1,666	2,704	124,685,000,000	73,340,000
Paper	[7] 10,158,000	[8] 6,730	[8] 2,520	4,210	42,765,000,000	25,156,000
Rubber	[9] 125,000	[9] 9,150	[9] 2,680	6,470	808,750,000	475,000
Total					257,664,323,000	151,563,000

SOURCES OF DATA

[1] Bureau of Mines/U.S. Department of the Interior.
[2] Oak Ridge National Laboratory (report No. ORNL-NSF-EP-24).
[3] Zinc content.
[4] Battelle Memorial Institute Report PB-245759, "Energy Use Patterns in Metallurgical and Non-Metallic Mineral Processing."
[5] Private communication from Arthur D. Little Corp.
[6] U.S. Bureau of Mines and Arthur D. Little estimates. (Receipts are used rather than consumption as figures for consumption do not distinguish between bome and purchased scrap.)
[7] U.S. Department of Commerce/Bureau of the Census.
[8] U.S. Environmental Protection Agency "Report to Congress," February 1973, pg. 11, table 4 (converted from Btu to kWh using standard conversion of 1 kWh equals 3,413 Btu).
[9] Industry estimates.

The CHAIRMAN. The next witness will be O. Pendleton Thomas, chairman of the board and chief executive officer, B. F. Goodrich Co., speaking on behalf of the Petrochemical Energy Group.

We are very happy to welcome you here, Mr. Thomas.

STATEMENT OF O. PENDLETON THOMAS, CHAIRMAN OF THE BOARD AND CHIEF EXECUTIVE OFFICER, B. F. GOODRICH CO., ON BEHALF OF THE PETROCHEMICAL ENERGY GROUP

Mr. THOMAS. Thank you, Mr. Chairman and Senator Packwood. As you already indicated, I am O. Pendleton Thomas, chairman and chief executive officer of B. F. Goodrich Co. Today I am speaking on behalf of the Petrochemical Energy Group, sometimes known as PEG, a group of some 21 independent petrochemical companies who use oil and gas to produce the major portion of the petrochemical intermediates in the United States. PEG companies compete with the petrochemical arms of the major integrated oil companies, as well as foreign petrochemical companies.

We applaud the President's goals for our national energy policy but have concern about the measures proposed to reach them. We have grave doubts that the energy savings promised justify the cost and complexity of the administration proposals.

As you are aware, the amounts they advocate just for the U.S. Department of Energy, runs $1,300 a year for each family of four in this country.

We continue to believe that development of U.S. energy resources is best accomplished through complete deregulation of prices and that a windfall profits tax would assure that an appropriate amount of earnings are utilized for energy development.

However, if taxation is to be the means of assuring appropriate market prices, then certainly we need to plow back a portion of revenues collected into energy sources.

By the same token, if taxation is to be the mechanism for encouraging conservation and conversion to coal, administration proposals should be altered to reflect the realities of our industry. Taxes imposed on our industry would be passed on to the consumer, thus causing additional inflation without the potential of offsetting benefits from increased energy supplies.

Tax measures in S. 1472 designed to encourage conservation and conversion ignore the fact that there are no substitutes for petrochemical feedstocks and some process fuel uses of oil and gas. We are pleased to note that Secretary Schlesinger recognized the unique nature of petrochemical feedstocks in his testimony before this committee on Monday.

The proposed tax measures would raise the cost of our fuel and feedstock above the world price paid by our competitors abroad, causing us to lose exports and even domestic markets and the jobs they support.

They provide no incentive for increased production of our domestic oil, natural gas, and natural gas liquids.

Finally, the tax bill passed by the House would, in some cases, give a tax preference to the use of natural gas liquids for boiler fuels where fuel oil would otherwise be used.

Let me briefly explain why we have reached these conclusions.

First, consumption taxes.

Consumption taxes can only work where there is opportunity for conversion to coal or for conservation. As the Ways and Means Committee and the Ad Hoc Energy Committee recognized, there is no practical opportunity for conversion of the feedstock use of oil, natural gas, or natural gas liquids.

Probably until the 1990's, petrochemical production is totally dependent on oil and gas raw materials. Consequently, it is very important that this committee adopt the same definition of taxable use as reported by the Ways and Means Committee. Ways and Means specified that taxable use means any use as a fuel in a trade or business.

The Ways and Means Committee also recognized that there is no practical opportunity for conversion or conservation for some fuel uses of oil and natural gas in processing applications.

I am not talking about boiler fuel use. I mean, for example, use of natural gas as fuel in cracking furnaces to produce ethylene, or in reforming furnaces to produce methanol and ammonia, or for the finishing of fibers and tire cord. Process gas is essential where precise temperatures or flame characteristics are required in a manufacturing process.

The administration's consumption tax proposal also creates incentives for use of scarce natural gas liquids as boiler fuel in preference to oil. Fuel use of oil would be taxed at the oil rate but natural gas liquids would be taxed as natural gas.

Thus, fuel oil users would, in many cases, pay a higher tax, creating an incentive for them to switch to natural gas liquids needed for nonsubstitutable feedstock and process users.

We urge you to eliminate this incentive by placing boiler fuel use of propane, ethane, and butane under oil-use tax rates. This would tax boiler fuel use of oil and natural gas liquids on an equal basis.

Next, natural gas liquids equalization taxes.

An unequal application of the natural gas liquids equalization tax could result from the controlled price definition in the House bill which deals with calculating this tax. In my written testimony on page 8, I have suggested language which would eliminate this technical problem.

Still another matter we urge the committee to consider is whether it is necessary to raise the cost of our fuels above world oil prices which our foreign competitors pay.

Producing petrochemicals requires a great deal of fuel. Proposed consumption taxes are designed to drive oil costs above world oil costs and to raise natural gas to the price of No. 2 oil. We find it difficult to understand why the objective of inducing conversion from oil and gas to coal or conservation requires taxes which would raise prices above those our foreign competitors must pay for their fuel.

In addition to these tax-related problems, other measures the President has proposed have serious potential for creating dislocations in our industry.

For instance, mandatory coal conversion provisions coupled with unrealistic clean air requirements would force us to make large investments in new boiler equipment and pollution-control facilities. Recent testimony before the House Energy and Power Subcommittee causes us to have grave doubts that there are adequate production and transportation facilities to accommodate massive conversion to low-sulfur coal.

The petrochemical industry will also face a serious threat of feedstock shortages and feedstock price increases if the national energy plan increases liquid-based synthetic gas production, as now proposed. Section 415 of S. 1469 would encourage construction of large, new SNG plants by extending Federal Power Commission jurisdiction to them.

We understand the gas industry has urged exemption from the equalization tax of oil and gas liquids used for SNG production. Yet, as evidence submitted to FEA hearings on July 11 and 18 established:

In the production of SNG, 10 to 20 percent of the energy content of the feedstock is lost.

Increased SNG production could cost the U.S. economy up to $2.5 billion annually as compared to using alternate fuels.

Employment could be adversely affected by SNG production. SNG which also would raise the costs of fuel to the entire economy.

A survey of all 12 SNG plant operations last year confirms that SNG plants sell large volumes of gas directly or indirectly to boilers with dual firing capability to keep SNG plants operating even when residential-use loads are down.

The result is that high-priority consumers, whose needs can be met by pipeline gas, subsidize SNG use by low priority consumers. Attached to my written testimony is a more complete discussion of the high cost to residential consumers and other problems which would result from increased SNG production.

In summary, our industry must be concerned about all of these cost impacts for we face vigorous competition from abroad. In 1972, approximately 40 percent of the world's petrochemical plants were in the United States but in the last 5 years less than 15 percent of the world's new and proposed plants were located here.

If our costs, because of taxes and regulations, are pushed too high, the U.S. petrochemical industry will, in effect, be forced abroad.

As a result, we would import expensive foreign oil in such forms as textiles and clothing, plastics, medicines, fertilizers, pesticides, and tires—at the equivalent of $50 to $200 a barrel instead of $13.50 per barrel of crude oil; the U.S. would lose our industry's export market which in 1976 provided a positive trade balance of over $4.1 billion; as we lose export markets, we would lose production and jobs in direct petrochemical production.

Lost production would have a large downstream economic impact on production and jobs in other U.S. industries—those who buy our synthetic rubber, fibers, plastics, and agricultural chemicals.

The basic U.S. petrochemical industry directly employs more than 390,000 people in over 1,000 plants with annual sales of $41 billion. Downstream consumers, who depend upon petrochemicals in manufacturing, construction, and crop producing industries and service industries, directly employ almost 11 million people with a payroll of nearly $77 billion per year.

Thank you. I would be glad to respond to any questions.

The CHAIRMAN. Let me say to you what I said to the other witnesses, Mr. Thomas, that you have provided us with very valuable, substantial member of the committee and the staff. I know I will do justice to it, and our staff will do justice to it. I hope each Senator will take it home with him. We are sending it to those who are not here now, and we hope they will all carefully study this, so that our deliberations will reflect consideration of the points you raise.

That is why I wanted to hold these hearings during the recess, so that every member could receive this information and benefit from it and thoroughly understand it during the recess so that when we come back, we will be a lot better informed on the subject.

I appreciate your statement here and the backup information you provided us.

Senator Packwood?

Senator PACKWOOD. I have no questions.

The CHAIRMAN. Senator Roth?

Senator ROTH. Yes; Mr. Chairman, I would like to ask one or two questions.

I am sorry I missed part of your testimony, but I wonder if you could tell me what the balance of trade is today that results from the petrochemical industry?

Mr. THOMAS. As I indicated in my testimony, last year we had a favorable balance of trade of $4 billion, a little over $4 billion. Those are the latest numbers we have at the present time for 1976.

Senator ROTH. If the President's program were put into effect, what would be the impact on petrochemical industry, and what impact would that have on our balance of trade?

Mr. THOMAS. The petrochemical industry is a large consumer of hydrocarbons because of its feedstock needs and also its very large fuel needs and, as a result, the new cost that would be incurred that would have a substantial impact on the petrochemical industry, we think, as great or greater than any other industry. These prices would have to be passed through to the consumer, as my testimony indicates, because we certainly could not absorb them.

At the present time, the return on assets of the 21 companies that make up the PEG group last year was just under 7 percent. I think that this indicates that this is less than the cost of capital to these companies today. We would have to pass these through, and we think that if we are not able to do it, it will have a negative effect, that our costs will be so high then that it will encourage the importation of petrochemicals from abroad, because they can undersell us from a price standpoint.

Senator ROTH. That is my understanding, that the effect of the program would be to not only have a very serious effect on what we could export and sell abroad, but it would also have a very serious effect on prices and jobs in this country.

I guess one thing peculiar to your industry is that you have no alternative to these feedstocks; you must use them.

Mr. THOMAS. I am glad we got our point across to you.

Senator ROTH. Thank you, Mr. Chairman.

The CHAIRMAN. Are there any further questions, gentlemen?

Thank you very much.

Mr. THOMAS. Thank you, Mr. Chairman.

[The prepared statement of Mr. Thomas follows. Oral testimony continues on p. 458.]

STATEMENT OF O. PENDLETON THOMAS

SUMMARY

PEG does not support either the equalization or consumption taxes. Deregulation of oil and gas would be the most effective way to induce conversion and conservation. It would also stimulate supplies.

Any taxes imposed on the petrochemical industry must be passed on to the consumer, thus generating substantial additional inflation without potential of offsetting benefits from increased supply. This is particularly true when tax rates are set to drive energy costs above the world oil price.

If there are to be such taxes (*a*) Consumption taxes should not be imposed on petrochemical feedstocks or nonsubstitutable process uses; (*b*) Equalization taxes on natural gas liquids should be measured from the supplier's ceiling price—not from either an arbitrary composite price or from spot prices; and (*c*) Taxes should not encourage boiler fuel users to switch to natural gas liquids either by direct burning or SNG.

STATEMENT

Mr. Chairman, Members of the Committee, I am O. Pendleton Thomas, Chairman and Chief Executive Officer of the BFGoodrich Company. Today, I am speaking on behalf of the Petrochemical Energy Group (PEG), a group of some 21 independent petrochemical companies who use oil and gas to produce the major portion of the petrochemical intermediates in the United States, PEG companies compete with the petrochemical arms of the major integrated oil companies, as well as foreign petrochemical companies.

We applaud the goals chosen by the President for our national energy policy. However, we are concerned about the means selected to reach these objectives. Since the chemical industry is the largest industrial user of energy—for nonsubstitutable feedstocks and process uses, and also for fuel uses, our customers will pay the taxes that have been proposed.

Any taxes imposed on the petrochemical industry must be passed on to the consumer, thus generating substantial additional inflation without potential of offsetting benefits from increased supply. Consequently, we have taken a hard look at the proposals before you. Frankly, we doubt the effectiveness of using the tax system to accomplish energy policy objectives. Trying to affect energy resource allocation using the tax system is inefficient and costly and only slightly less draconian than government rationing.

The actual impact of these tax measures on energy use decisions, whether of industry or of the millions of individual consumers across the country, is impossible to predict. Deregulation of the price of oil, gas and natural gas liquids would allow free market forces to do the resource allocation job and, in our view, would be far more likely to accomplish the President's energy policy goals.

Even if taxes are the chosen means of working toward the President's goals, the tax measures proposed, when combined with a highly complex system of energy price regulation, may simply be impossible to administer.

Achievement of national goals may actually be frustrated by some aspects of the tax proposals:

First, the Administration's tax proposals raise the cost of fuel and feedstock to the manufacturers of this nation above the world price of oil to our competitors abroad.

These cost increases would have a negative impact on exports and imports. They would increase U.S. dependency on foreign sources of petrochemicals, and they would most certainly have an adverse effect on our industry's positive contribution to the nation's balance of payments—which was in excess of $4 billion last year.

Second, Administration tax proposals ignore the fact that there are no substitutes for some essential uses of oil and gas. Prime examples include the use of oil, natural gas, and natural gas liquids as raw materials, or petrochemical feedstocks, as we call them, to make man-made fibers, plastics, agricultural chemicals and medicines. Another major industry totally dependent on petrochemical feedstocks is synthetic rubber which today accounts for 78% of rubber consumption in the U.S.

Third, the proposed taxes provide no incentive for increased exploration, development, and production of our domestic oil, natural gas, and natural gas liquids.

Recommendations

If it is determined by this Committee and the Congress that equalization and consumption taxes should be imposed on our industrial base, then we urge that:

Consumption taxes should be imposed only where there is a practical opportunity for conversion from, or conservation of, oil, natural gas, and natural gas liquids. This is consistent with the President's Message to the Congress on April 20, 1977, although inconsistent with S. 1472, the tax portions of the Administration bill. Neither feedstock use or nonsubstitutable process use should be subjected to a tax to compel conversion since these uses have no practical opportunity for conversion. The Ways and Means and Ad Hoc Energy Committees of the House adopted the principle we advocate here.

This should be corrected by making natural gas liquids used for boiler fuel subject to the same consumption tax as oil for boiler fuel. Note that 30 percent of our liquified petroleum gas is refined from oil but would be taxed at the natural gas consumption tax rate, making the problem still worse.

(2) SNG plants should not receive tax preference for the use of natural gas liquids—or naphtha—as their feedstock. Two present SNG plants are permitted by the FPC to charge up to $28 a barrel equivalent for SNG made from scarce liquid and petroleum products. Yet, if liquids are converted into SNG, the boiler fuel user, due to utilities' rolled-in pricing policies, would still pay no

more than the cost of No. 2 oil—about $12 a barrel, a result encouraging massive waste of scarce resources.

I will now briefly discuss the import and significance to our industry, and the nation's energy objectives of these recommendations.

Consumption Taxes

Consumption taxes can only have their intended result, where there is opportunity for conversion to coal or for energy conservation. As the Ways & Means Committee and the Ad Hoc Committee recognized, there is no practical opportunity for conversion of the feedstock use of oil, gas or natural gas liquids. Today and probably until the 1990's, petrochemical production is totally dependent on oil and gas raw materials. It is very important that this Committee adopt the same definition of taxable use as in Section 4992(a) of H.R. 8444 (as reported by the Ways and Means Committee) specifying that taxable use means "any use as a fuel in a trade or business."

Equalization taxes should be imposed on a consistent basis so that the tax laws will not provide a competitive advantage based solely on the form of the product used—or who one's supplier happens to be. Here our concern focuses on the taxing of natural gas liquids as part of the crude oil equalization tax, a measure added by the House to the President's Bill. We urge that the tax, if any be imposed, be measured from each vendor's ceiling price, not from some arbitrary, average price, since price controls on natural gas liquids yield widely differing prices.

Taxes should not create an incentive for wasteful boiler fuel users to use scarce natural gas liquids instead of fuel oil—whether the boiler uses the liquids directly as fuel or as synthetic natural gas.

(1) Natural gas liquids used for boiler fuel should be subject to the same consumption tax as oil for boiler fuel. Under the Bill before the House, a boiler fuel user may be able to use, say, propane as a fuel and, with the equalization and consumption taxes added, pay no more than the cost of No. 2 fuel oil. But if he uses No. 2 fuel oil, he must buy the No. 2 fuel oil at a price which includes the crude equalization tax, and also pay a consumption tax. Therefore, the boiler fuel user may pay a lower consumption tax if he burns propane. The result is to create wasteful boiler fuel demand and take nonsubstitutable natural gas liquids from farmers, petrochemicals, and other feedstock and process users.

The Ways and Means Committee also recognized that there is no practical opportunity for conversion or conservation for some fuel uses of oil and natural gas in processing applications.

While only the petrochemical industry uses oil, natural gas and natural gas liquids as raw materials, many industries including petrochemicals use oil and gas as process fuels—steel, glass, textiles, automobiles—just to name a few. I am not talking about process steam, or any boiler fuel use at all, but rather, for example, use of natural gas as fuel in cracking furnaces to produce ethylene, or in reforming furnaces to produce methanol and ammonia, or for the finishing of fibers and tire cord. Natural gas is used by other industries for direct flame application on textiles, on paints, on specialty steels, or where precise temperatures or flame characteristics, in a manufacturing process, are essential.

The President said in his April 20 Congressional address: "We must be sure that oil and natural gas are not wasted by industries and utilities that could use coal instead. Our . . . strategy will be conversion from scarce fuels to coal *wherever possible*."[1] (Emphasis added.)

Nonsubstitutable feedstocks or process and plant protection uses should not be subject to a tax designed to drive up costs to induce conversion to coal.

Moreover, to the extent that there is conservation potential in such uses, present energy prices are bringing these savings about.

Eliminate Incentives for Boiler Fuel Use of Liquids

Another important deficiency in the Administration proposal lies in its incentives for use of scarce natural gas liquids as boiler fuel. The consumption tax proposed would actually encourage use of natural gas liquids for boiler fuel in preference to oil. Fuel use of oil would be taxed at he oil rate, i.e. 30¢ in 1979 rising to $3.00 by 1985. But natural gas liquids are taxed as natural gas, i.e. a tax rising no higher than the difference between the user's acquisition cost and

[1] Text of an Address by the President to a Joint Session of Congress On Energy, April 20, 1977, p. 6.

the cost of No. 2 oil. Thus fuel oil users would, in many cases, pay a higher tax, creating an incentive for them to switch to natural gas liquids needed for non-substitutable feedstock and process users such as farmers and petrochemical companies.

We urge you to place boiler fuel use of propane, ethane and butane under the oil tax rates in order to eliminate the proposed built-in incentives to waste these scarce, clean hydrocarbons under boilers. This can be accomplished by amending the consumption tax definition of "natural gas" in section 4995(b)(1)(B) to include only those products of natural gas or petroleum which have an API gravity number of 300 or more.

Natural Gas Liquids Equalization Tax

It is essential that the "price gap" definition in the natural gas liquid equalization tax be clarified to express the stated intent of the Ways and Means Committee in regard to collection of that tax.

As you know, a natural gas liquids equalization tax would be imposed in the amount of the difference between the controlled price of a natural gas liquid to its first purchaser for end use and the local No. 2 oil price.

Unlike the situation with crude oil, the price of natural gas liquids to a purchaser will vary significantly from vendor to vendor. The Ways and Means Committee on H.R. 6831 observes that "the controlled price of the liquids is different for every seller because it depends on several variables, the most important of which is permissible cost passthroughs for the seller." The Committee report therefore specified, at page 80, that the term "controlled price" is "the controlled price of a particular vendor for the sale of a particular liquid at a particular time."

Thus it is clear, as well as logical and reasonable, that the equalization tax is to be determined with respect to specific sales by specific sellers. But the language of the tax provision itself does not make this point clear. We would suggest that section 4988(d)(1)(B)(i) defining "controlled price" be amended to read as follows:

". . . the ceiling price applicable to such sale of the particular vendor of the particular liquid at the time of such sale under section 4(a) of the Emergency Petroleum Allocation Act of 1973."

Without this distinction it is conceivable that "controlled price" might be defined administratively as an average price for a region. This would result in random penalties and advantages for users within the region.

Tax Overkill

The process of producing petrochemicals requires not only nonsubstitutable feedstocks but also a great deal of fuel. This fuel would be subject to consumption taxes. While we have not opposed the principle of taxing fuel uses where there is conversion potential, these taxes would be set so that our fuel oil costs will be pushed above world oil costs and natural gas will rise to the price of No. 2 oil. We find it difficult to understand why the objective of inducing conversion from oil and gas to coal, or conservation, requires taxing up prices above those our foreign competitors must pay for their fuel. Taxing our fuels above the world market prices is a dangerous measure of overkill. Moreover, the "equalization" taxes on crude oil and natural gas liquids will be imposed or passed through not only to our fuel uses but also to our nonsubstitutable feedstock and process uses.

And you should keep in mind that these increased costs pass through the economy to the ultimate consumer. The greatest part of our industry's costs are our feedstocks, fuel and other energy costs that will be significantly affected by the proposed tax program. The entire business community is concerned, and with good reason, about continuing inflation. These taxes can only increase inflationary pressures.

Costs and Uncertainties

This Committee should realize, in looking at the package before it, that very substantial increased non-tax costs will be imposed on us by the other measures the President has proposed.

Mandatory coal conversion provisions coupled with, sometimes unrealistic, clean air requirements will force us to make large investments in new boiler equipment and pollution control facilities—investments which will not increase our productive capacity, or our ability to boost employment or contribute to economic growth. In addition, recent testimony before the House Energy and Power Subcommittee indicates that coal production and transportation facilities will not be adequate to supply us with low sulfur coal from the West, if we are all forced to convert our boilers![2]

The petrochemical industry will also face a serious threat of feedstock shortages and feedstock price increases if the National Energy Plan increases liquid-based synthetic gas producton, as now proposed. Section 415 of S. 1469 would encourage construction of large, new SNG plants by extending Federal Power Commission jurisdiction to them. We understand the gas industry has urged exemption from the equalization tax of oil and gas liquids used for SNG production. Yet, as evidence submitted to FEA hearings on July 11 and 18 established, SNG was not needed last winter, and will not be needed, to meet high priority natural gas consumers' needs.

FEA studies[3] have predicted that expanded SNG production could consume up to 33 percent of the domestic production of natural gas liquids, causing U.S. dependence on imports to increase. Prices of propane, butane and naphtha would rise to historical users such as farmers, rural residents and petrochemical manufacturers. Yet many historical users have no alternative to using these liquids for process use or raw materials.

Evidence at the FEA hearings also indicated that:

In the production of SNG, 10 to 20 percent of the energy content of the feedstock content is lost.

Increased SNG production could cost the U.S. economy up to $2.5 billion annually as compared to using alternate fuels.

Employment could be adversely affected by SNG production which would raise the costs of fuel to the netire economy.

A survey of all 12 SNG plants' operations last year confirmed that SNG plants sell, directly or indirectly, large volumes of gas to boilers with dual firing capability to keep SNG plants operating even when residential use loads are down. The result is that high priority consumers, whose needs can be met by pipeline gas subsidize SNG use by low priority consumers. Attached to my written testimony is a more complete discussion of the high cost to residential consumers and other problems which would result from increased SNG production. This statement, filed with FEA, contains a detailed survey of the operation of existing SNG plants in the continental U.S. which proves their production was not required to prevent curtailment of high priority consumers last winter.

Administrative Complexity and Uncertainty

Any system relying on government price regulation rather than market pricing brings with it a large measure of uncertainty and arbitrary and unpredictable shifts in pricing and allocation of our resources and our products which market pricing would avoid. Yet we understood that one of the key principles of the President's National Energy Plan was to establish predictability and certainty in the energy area[4] so that industry, consumers and investors can all plan with some degree of confidence.

But it is the staggering administrative complexity of the energy pricing and taxation structure proposed in the total energy package now before Congress that concerns us as much or even more than the various cost factors. Many of us in industry have struggled with the problems, uncertainties and massive bookkeeping problems associated with existing FEA pricing and allocation regulations.

But the National Energy Plan would add more complex natural gas pricing, and an extremely complex "equalization" tax for crude oil and natural gas liquids. It would also add consumption taxes for oil, natural gas and natural gas liquids and a new system for calculating rebates and credits for certain investments in energy equipment. At the same time, it would remove or revise existing investment tax credit regulations. In all candor, we simply wonder if this system can operate at all. If it can, we are greatly concerned about the costs not only to industry, but to the taxpayers for the staff that will be required to administer it.

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[2] Testimony of Governor Julian M. Carroll, May 25, 1977, p. 7; Statement of Donald C. Lutken on behalf of Edison Electric Institute, before the Subcommittee on Energy and Power, Interstate and Foreign Commerce Committee, United States House of Representatives, May 25, 1977, pp. 7–11; Letter of Carl E. Bagge, National Coal Association, to Honorable John D. Dingell, May 23, 1977, pp. 12–14.

[3] Estimate based on data in the FEA's "Draft Programmatic Environmental Impact Statement on the Allocation of Petroleum Feedstocks to Synthetic Natural Gas Plants," p. 3.2–50.

[4] National Energy Plan, p. 30.

The new Department of Energy, alone, will have a budget of $10.6 billion.[5] We expect expansion of the Internal Revenue Service will also be necessary.

The Role of the Petrochemical Industry

Our industry must be concerned about costs, for we face vigorous competition from abroad. The petrochemical industry began in the United States. In 1972, approximately 40 percent of the world's petrochemical plants were in the U.S. However, in the last five years, less than 15 percent of the world's new and proposed plants are being built here. The great majority of new petrochemical facilities are being built in other nations.[6] Thus, if our costs, because of taxes and regulations—factors we cannot control—are pushed too high, the U.S. petrochemical industry will, in effect, be forced abroad.

We would import expensive foreign oil in such forms as textiles and clothing, plastics, medicines, fertilizers, pesticides, tires—at the equivalent of $50–$200 a barrel or more instead of $13.50 per barrel crude oil;

We would lose our export market which in 1976 provided a positive trade balance of over $4.1 billion;

As we lost either our markets or our nonsubstitutable feedstocks and process fuels, we would lose production and jobs in direct petrochemical production to compound an already difficult unemployment situation.

Petrochemical intermediates are widely used in so many industrial and consumer products, that lost production would have a large downstream economic impact on production and jobs in other industries—those who need synthetic rubber, fibers, plastics, agricultural chemicals, to name a few.

The basic U.S. petrochemical industry directly employs more than 390,000 people in over 1,000 plants with annual sales of $41 billion. But the downstream consumers, dependent on petrochemicals in manufacturing, construction, and crop producing industries and service industries, directly employ almost 11 million with a payroll of nearly $77 billion per year in every state of the nation.

One independent study reports that just a 15% sustained decline in petrochemical feedstock supplies will result in the loss of 1.6 to 1.8 million jobs throughout the U.S. economy—and a loss of $65–70 billion annually in domestic production value.[7]

For comparison, in 1975 our industry directly provided over three times as many jobs as the U.S. petroleum refining industry, more than 50 percent more new capital investment, and double the value added. Looking at size another way, the petrochemical industry's value added contribution to the economy nearly equals the paper industry and slightly exceeds that of the primary steel industry.[8]

We hope the proposals finally approved by this Committee will allow us to continue to maintain a vigorous domestic petrochemical industry. The entire U.S. economy depends upon our doing so.

Encourage Domestic Production

The costs and uncertainties of the President's plan would be far more acceptable if the plan included a commitment to develop the vast domestic energy resources that still are available in this country. But we see no real production incentives in the President's program. We have often stated our willingness to pay free market prices for energy if we can return to a free market in energy resources. Federal price controls have been extremely damaging to supply. The most direct and efficient means of pricing oil and gas at their true replacement costs, encouraging conservation and efficient use, and stimulating increased domestic production is deregulation of oil and gas prices. A windfall profits tax on producers can solve any problem of unjustified price increases or use of profits outside the energy development or production areas.

If taxation is to be the means chosen to simulate market prices, then certainly we need to plow back a portion of revenues collected into energy production. We should not give up on American production. If new supplies are not produced, we will not have to pay for them. If, as we believe, the resources are there, they should be developed with as much speed as possible.

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[5] Washington Post, August 5, 1977, p. 12.
[6] Arthur D. Little, Inc., "1976 Petrochemical Industry Profile," Table 17.
[7] United States Petrochemical Industry Impact Analysis, Arthur D. Little, Inc., November 1973.
[8] U.S. Department of Commerce, Annual Survey of Manufacturers, 1975, pp. 12, 14.

Conclusion

If I may briefly summarize—

PEG does not support either the equalization or consumption taxes. Deregulation of oil and gas would be the most effective way to induce conversion and conservation. It would also stimulate supplies.

If there are to be such taxes—

(*a*) Consumption taxes should not be imposed on petrochemical feedstocks or nonsubstitutable process uses;

(*b*) Equalization taxes on natural gas liquids should be measured from the supplier's ceiling price—not from either an arbitrary composite price or from spot prices; and

(*c*) Taxes should not encourage boiler fuel users to switch to natural gas liquids either by direct burning or SNG.

I hope you and the Committee staff will feel free to call on us if we can be of assistance in working to mitigate these problems.

TESTIMONY OF THE PETROCHEMICAL ENERGY GROUP

FEA QUESTIONS AND PEG ANSWERS

Question 1. If the fuel conversion to coal from oil and gas and other conservation regulatory measures contained in the National Energy Plan are implemented, what market is foreseen for SNG?

Answer. None. PEG can find no evidence of need for current SNG production even during the past winter heating season. Conservation and conversion measures like those in the NEP, development of adequate gas storage facilities, proper management of pipeline gas supplies, pricing policies that stimulate the exploration and development of natural gas and petroleum, and development of coal-based SNG will eliminate any claimed need for SNG.

Question 2. Are there any regions or areas of the country where SNG (on a systems basis) is more efficient than alternative energy supply delivery systems?

Answer. No.

Question 3. Are there any regions or areas of the country where the use of SNG rather than alternative supplies has a significant beneficial environmental impact? In these regions, would the benefit still be significant if the SNG were used only by high priority customers?

Answer. No. See question 10.

Question 4. Should FEA require that all new SNG feedstock allocations be imports?

Answer. Yes. It is entirely proper to require the SNG plant to bear the costs and inconveniences of imports rather than take domestic supply from a traditional user. But requiring any allocations for SNG, whether of domestic or foreign feedstocks, will increase total U.S. demand for naphtha and LPG forcing greater reliance on imports and resulting in increased balance of trade deficits. No SNG allocations are needed.

Question 5. Should new, revised criteria be applied to future allocations to existing SNG plants as well as to new and expanded SNG plants?

Answer. No, present criteria should be applied to all.

Question 6. What will the economic impact be on the supply and demand for petroleum feedstocks and on traditional customers of these feedstocks in the event that the existing FEA allocation policies are revised to increase the number of SNG feedstock allocations?

Answer. Traditional customers will lose supply which will have to be made up, if at all, through more expensive imports. Balance of payments, barriers to trade, employment and investment must be considered.

Question 7. Should FEA establish a priority of fuels/feedstocks as a policy or criterion for SNG feedstock allocations? Would a "heavier the better" policy for feedstock priority make sense considering both security of supply and potential availability of supplies?

Answer. If FEA is to allocate any liquid hydrocrabon feedstocks for SNG manufacture, the "heavier the better" policy makes sense.

Question 8. If FEA established a policy which limited new SNG feedstock allocations to plants which were financed on a 10 to 15 year basis rather than on a 20 to 30 year basis, what would the impact be on costs, prices, future capital availability, utilization of alternative supply sources, etc.?

Answer. The impact of 20–30 year financing of SNG plants as opposed to 10–15 year financing is to increase the profits that an SNG manufacturer will make. Utilities are not allowed to make a profit on the sale of purchased natural gas; they can only recover the cost of natural gas in their rates.

SNG is another matter. The utility wishes to place its SNG plant in its "rate base." Thereafter, each year, the utility will include in its rates a "return" component which covers the interest on debt and earnings for the stockholders of the equity securities. The longer the plan stays in the rate base before it is depreciated out, the greater the earnings of the stockholders, since the rate base (less depreciation) is multiplied by the established rate of return to calculate the "return" component, to which an almost equal amount is added to shelter the return from federal income taxes.

For illustrative purposes, consider a 250 million dollar SNG plant, straight line depreciation, and a 10 percent rate of return.

With a ten-year depreciation, the return will be 137.5 million dollars total.

With a thirty-year depreciation, the return at the end of ten years will already be 212.5 million dollars and twenty more years of return to go!

Question 9. Should feedstock allocations be granted for base load plants or seasonal plants? To what extent is the cost of the SNG reduced by operating a plant on a year-round basis?

Answer. Seasonal. The operating and feedstock costs are the greatest costs, and operating year around carries the illusion of lowering unit costs but actually increases overall costs to the high priority consumer who pays for SNG year around when he doesn't need it.

Question 10. Should SNG feedstock allocations be granted for the purpose of providing supplies to new residential, commercial and other high priority loads?

Answer. No. FEA's recently completed Draft Environmental Impact Statement (DEIS) shows SNG would be used for low priorities while increasing the price to residential and other high priority consumers.

Question 11. What are the most recent developments in SNG technology? What commercial processes are available that can utilize a variety of feedstocks such as residual oil and crude oil? What improvements can be anticipated with regard to presently available reforming technology?

Answer. SNG can be manufactured from a variety of feedstocks such as residual oil, crude oil, municipal refuse and coal.

Question 12. What effect will the incremental pricing provision included in Section 414 of the proposed National Energy Act have on SNG demand?

Answer. Incremental pricing, the best way to determine true economic demand for SNG, would reduce or eliminate demand, but § 414 places a ceiling on the incremental rate which masks the SNG costs.

Question 13. What areas of the country have critical peak load needs that require new SNG plants? What class of customer (FTC priority) should be considered as having a critical need for purposes of SNG feedstock alloction?

Answer. None.

Question 14. What specific criteria should be proposed for review of SNG feedstock allocation applications?

Answer. Current criteria.

Question 15. Should the FEA allocation regulations be revised to cover all existing and potential SNG feedstocks?

Answer. If liquid based, yes.

TESTIMONY OF RALPH W. KIENKER

Mr. Chairman, members of the Panel, I am Ralph W. Kienker, Energy Affairs Director of the Monsanto Company. Today, however, I am appearing on behaf of the independent petrochemical companies who comprise the Petrochemical Energy Group (PEG).*

We appreciate the opportunity to appear today because we feel that the policy FEA adopts with respect to SNG production will have a crucial impact on the

*Borg-Warner Chemicals; Celanese Corporation; Chemplex Company; Dart Industries, Inc.; The Dow Chemical Company; E. I. du Pont de Nemours and Company, Inc.; Ethyl Corporation; The Firestone Tire & Rubber Company; Foster Grant Company, Inc.; The B. F. Goodrich Company; Goodyear Tire & Rubber Company; Hercules Incorporated; Monsanto Company; National Distillers & Chemical Corporation; Olin Corporation; Oxirane Corporation; PPG Industries, Inc.; Publicker Industries, Inc.; Rohm and Haas Company; Texas Eastman Company, a Division of Eastman Kodak Company; Union Carbide Corporation.

future of the independent petrochemical industry but also, we are convinced, on development of a sound national energy policy.

PEG has participated in FEA proceedings regarding SNG policy for several years and so we have had occasion to look very closely at the operation of existing SNG plants and also to give some consideration to the overall impact of SNG production on national energy supplies and the nation's economy. As my testimony will detail, we have concluded that both existing SNG production and any future additions to the capacity will inflict heavy costs on high priority consumers and on the nation's economy and is likely to detract from development of a rational energy policy for the nation.

In addition, after making as careful a study as available public data permits, we have concluded that SNG production is not needed now, was not required for high priority users even during last winter, and will not be needed to provide future natural gas requirements.

In the course of answering the questions set out by FEA, I have tried to organize the information requested in such a way that these costs to the nation are described and that evidence is provided supporting our belief that SNG production is not needed. Data from the FEA's own studies, including the recently issued Draft Environmental Impact Statement (DEIS) on the SNG program support our position. Of course, the gas industry itself has the best end-use data, but the industry has thus far provided no evidence to support their claim that SNG is needed for high priority users.

On the basis of all the evidence now available to us, we conclude that a change in policy that would encourage production of SNG at and certainly above present levels is not justified and would be a grave mistake for the nation's future.

I.

SNG IMPOSES UNACCEPTABLE RISKS, COSTS TO THE ECONOMY AND TO HIGH PRIORITY GAS CONSUMERS, AND IS IN CONFLICT WITH NATIONAL ENERGY PLAN OBJECTIVES

Costs to the high priority consumer

SNG plants will raise costs now, and far into the future, to high priority consumers for whom adequate supplies would be available even in a declining supply situation. For example, two plants[1] charge the equivalent of $24 and $29 a barrel of crude for SNG. The current average crude import price is $14.25 a barrel.

To illustrate the irrelevance of SNG to high priority consumers, we have displayed data from FPC filings by Columbia Gas System and from Columbia's 1976 Annual Report. The chart "Relative Significance of SNG in Meeting Residential and High Priority Commercial Requirements" demonstrates that, although Columbia has increased its firm requirements, its gas supply from reserves on hand at the end of 1976 and its projected LNG imports will be sufficient to meet priority one requirements through 1985 even if Columbia didn't purchase any new gas supplies.

The chart "Sources of Gas on Peak Days" shows the irrelevance of SNG production to total supply on a peak day for 1976–1977, if Columbia had just used its storage capabilities as it did in 1975–1976. The FPC Staff has found that Columbia imprudently diverted 7.5 Bcf of gas to boiler fuel and to consumers with alternate fuel capability between October 17–31, 1976. (Testimony of C. Hernandez in FPC Docket No. RP77–35, July 11, 1977, Appendix X.)

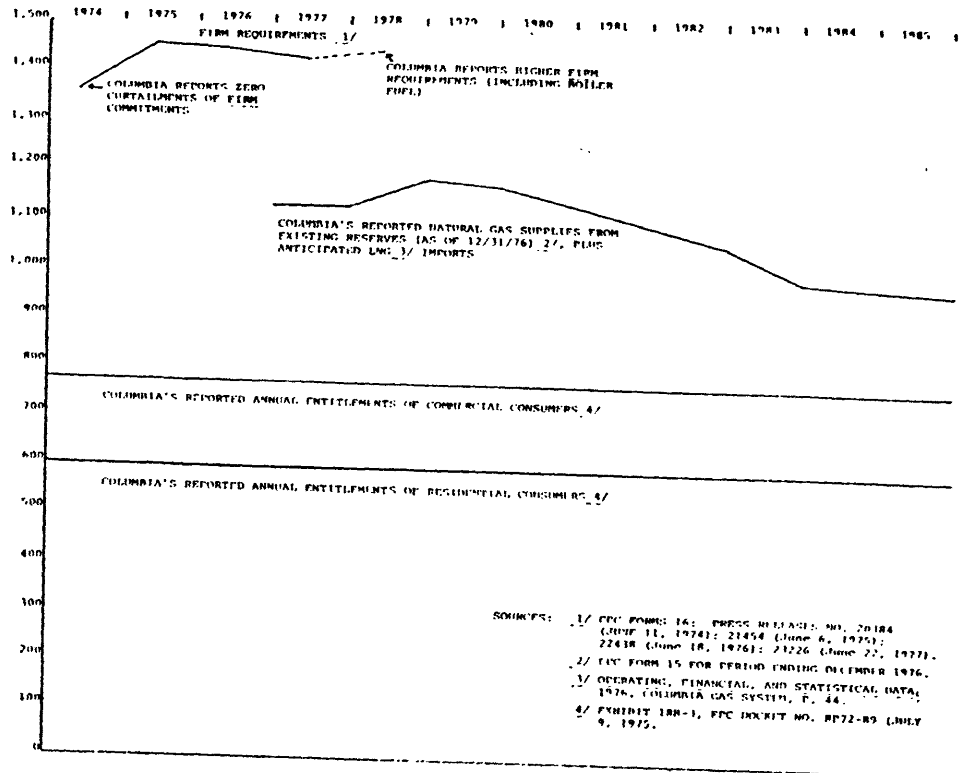
Looking at "Comparison of Volumes and Costs for Purchased Gas and SNG Feedstock—1976," it is clear that, despite the "contribution" of SNG to Columbia's total gas supply in 1976, the cost of SNG feedstock alone was 20.6 percent of the system's gas cost. This situation is not unique to Columbia.[2] The clear pattern where SNG facilities are in operation is that consumers bear massive costs for a very small increment of SNG which is not needed.

SNG plants seek to operate significant portions of the year and for many years to increase shareholders earnings as described on page ii. Consequently, gas utilities sell large volumes of gas to boilers with dual firing capability to keep SNG plants operating even when residential use loads are down. The PEG survey of SNG plant operations at Appendix C, confirms this pattern for the

[1] Algonquin SNG, Inc. charges about $5 per Mcf per letter to its customers, 2/2/77. Columbia Gas Transmission Corp. charges $4.14 per Mcf per its Annual Report, p. 7.

[2] See Appendix C.

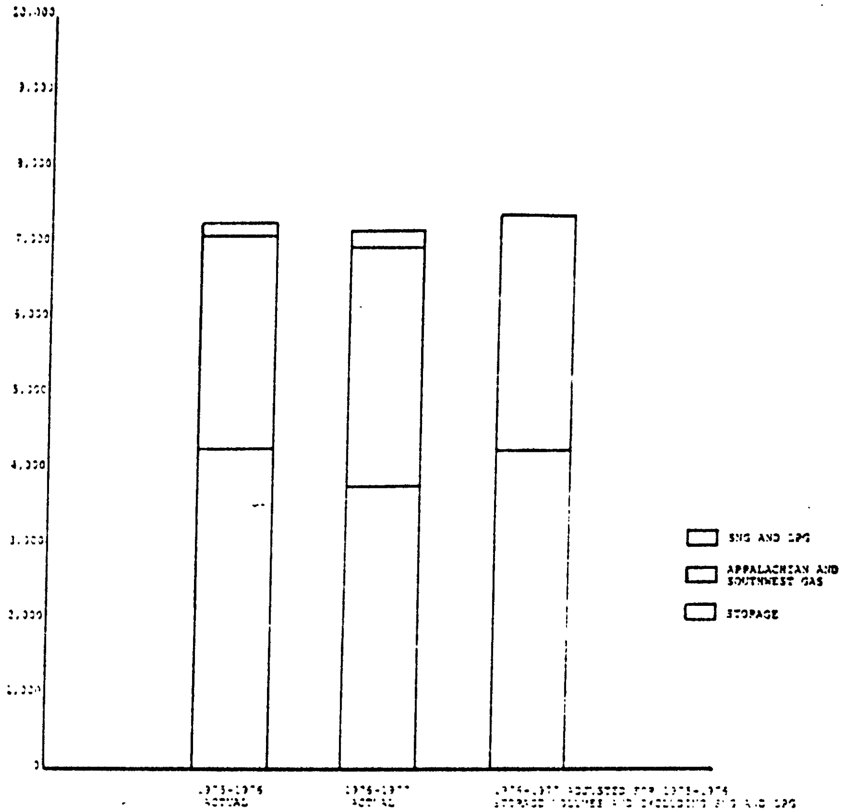
RELATIVE SIGNIFICANCE OF SNG IN MEETING RESIDENTIAL AND HIGH PRIORITY COMMERCIAL REQUIREMENTS - COLUMBIA GAS SYSTEM



NOTE: LINES ONLY CONNECT DATA POINTS

04-548-77-18

SOURCES OF GAS ON PEAK DAYS - COLUMBIA GAS SYSTEM



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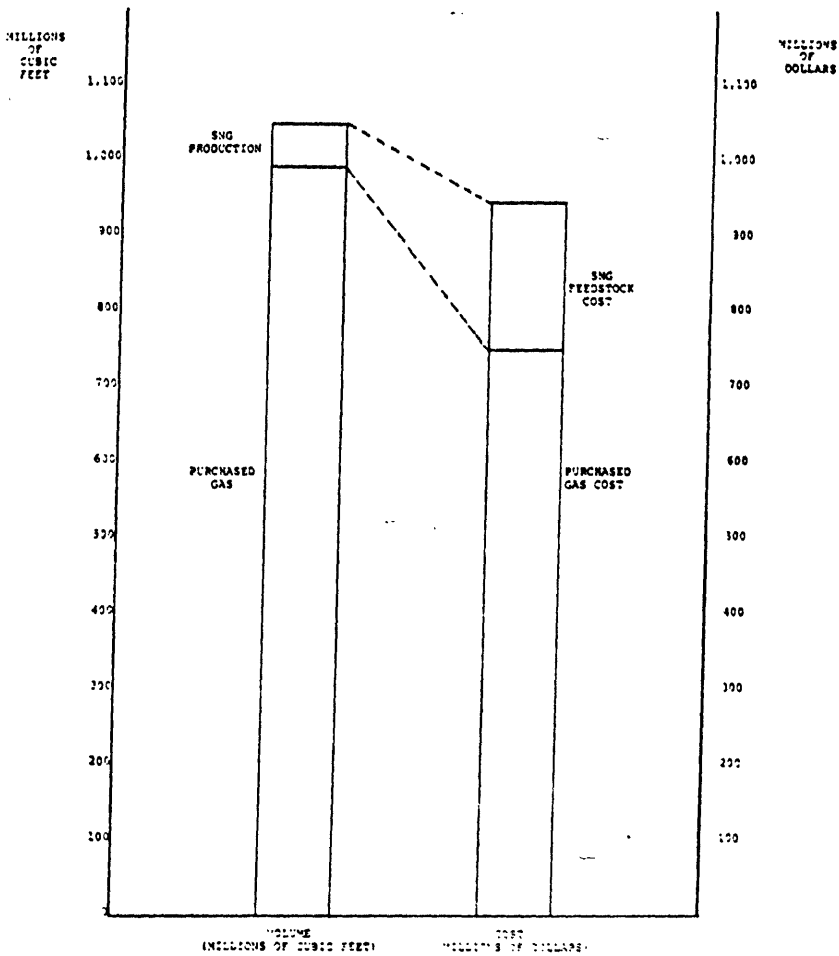
COMPARISON OF VOLUMES AND COSTS FOR PURCHASED GAS AND SNG FEEDSTOCK - 1976
(COLUMBIA GAS SYSTEM)



SOURCE: [illegible]

Consumers, Columbia, Peoples, Public Service Gas and Electric, Brooklyn Union and Commonwealth plants. Adequate public data was not available to assess the performance of the other operating plants. Such operations frustrate the objective of converting boiler fuel use of gas to other fuels, and support wasteful uses for the life of these costly SNG facilities.

On the other hand, if boiler fuel loads are not kept on line in order to take SNG, then the SNG would have to go into storage. As a result, cheaper natural gas will be shut in at the wellhead in order to protect a market for the high-priced SNG. In fact, this has already happened. Last fall, Columbia LNG Corporation backed off of natural gas purchases,[3] while increasing its own production and sales of SNG by over thirteen billion cubic feet in one year.[4]

It is difficult to sell boiler fuel gas to a dual-fired boiler at the equivalent of $18 to $29 a barrel, when even home heating oil is much cheaper. If the SNG comes from storage to which the costs of transporting, injecting, withdrawing, and the carrying charges for the investment and cushion gas have been added, the SNG is even more expensive. Thus, the gas utility will want to "roll in" the cost of the SNG, which means that the residential, commercial, and high priority industrial customers will subsidize the SNG for boiler fuel users. The agency's DEIS came to precisely this conclusion on the basis of computer models of the impact of SNG production.

"The production and use of SNG as a fuel has two closely related effects: (1) it supplies those customers who otherwise would do without gaseous fuels or use substitute fuels; and (2) when the high cost of SNG is averaged with natural gas, it raises the average price of natural gas to all consumers. (SNG production costs vary depending on such factors as the cost and sulfur content of the feedstock, but will generally be over $4.00 per Mcf, and in some cases could be as much as $6.50 per Mcf.) As the price of natural gas increases, the demand for gaseous fuels declines. Those customers who would have all their requirements fulfilled even without SNG production (e.g., most residential customers) would consume less natural gas. The net result is that SNG is available to fill the demands of low priority users. In addition, the resulting drop in natural gas consumption by high priority users allows lower priority users to increase their consumption of natural gas by more than the amount of SNG produced."[5]

The President's National Energy Program[6] suggests that SNG may be needed to meet emergency needs of high priority consumers in the near term. This is not, however, in accord with the actual plans of those who are urging FEA to change its SNG policy. In testimony before the FEA on July 11, both Northern Illinois Gas Company and the President of the American Gas Association stated that SNG from liquid hydrocarbons would be and should be relied upon by the industry for base load use over the long term, including through the year 2000.[7]

In changing its SNG policy, the FEA is being asked to make a decision that would increase gas prices to the consumer not only in the short term and not only when real shortage situations exist. High priority consumers will be asked to pay indefinitely so that low priority customers can have the benefit of SNG.

SNG is not in the interest of the high priority consumer. It is very much in the interests of the gas industry, however. As described on page ii, gas pipelines and local distribution companies make no profit on the sale of purchased gas, which they can buy at prices far lower than SNG can be produced. But SNG production yields these same companies a substantial profit by allowing a "return on investment" component for expensive SNG facilities. Thus FEA is being asked to allow the industry to choose the most profitable route to satisfy gas demand while ignoring the costs of this approach to consumers, to the Nation's energy security and to efficiency of energy use.

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[3] Affidavit of W. H. Howard on file with the FPC in *Metzenbaum v. Columbia Gas Transmission Corp.*, FPC Dkt. No. RP77-35 at 1-2.
[4] Columbia LNG Corporation, 1976 Annual Report, p. 4.
[5] DEIS, p. 3.2-9.
[6] NEP, p. 57.
[7] FEA Transcript, pp. 174-175, 61-62.

Several examples from the past winter illustrate the problem.

Northern Illinois Gas Company, which runs its SNG plant year-round, even last winter had gas supplies so far in excess of demand that it rescheduled 12 Bcf of pipeline gas which would have been delivered[8] during the December-March period, while serving loads at least as low as FPC priority category No. 5.[9] Yet NI-Gas operated its plant at full capacity all year, and is adding new load and projects construction of additional base load SNG facilities.[10]

Brooklyn Union Gas produced expensive SNG last winter costing $3.25 per Mcf,[11] but did not take advantage, even at the height of the winter shortage, of purchases until ENGA at a maximum of $2.25 per Mcf.[12] Moreover, Brooklyn Union has apparently used SNG to fill storage facilities when $2.25 ENGA gas remains available through August 1.[13]

Frustration of national energy plan objectives

Production of SNG will be in conflict with major principles of the President's National Energy Plan.

First, the intent of the NEP is to "reallocate natural gas to high priority uses." [14] Yet, as shown by the FEA's analysis cited above, SNG production makes gas available to low priority users over the long-term life of the SNG facilities.

Second, manufacture of SNG from liquid petroleum feedstocks is an inefficient use of those feedstocks. FEA's "Statement of Policy" [15] indicates that 8 to 10 percent of the Btu value of SNG feedstocks is wasted in the conversion process.[16] Our own analysis, based on data in the DEIS, indicates that the normal energy efficiency of liquid-based SNG production would be about 80 percent. Details of our analysis are attached at Appendix B.

Third, as discussed above, allocation of liquid petroleum feedstocks to SNG plants would force vast, increased imports of such products. Regardless of whether the policy is to divide up the existing domestic supply between historical users and the SNG plants, or to force SNG plants to rely on imported feedstocks, the result is to increase U.S. dependence on imported products and to make all U.S. consumers more vulnerable to supply interruptions. Products such as natural gas liquids and naphtha are particularly vulnerable because the worldwide sources for those products are far more limited than the worldwide sources for crude oil. Therefore, any policy which would force an increase in imports of natural gas liquids or naphtha, has more severe national security implications than the already apparent problem of reliance on crude oil from foreign sources.

The National Energy Plan encourages increased utilization of the United States' abundant coal supplies. The huge, long-term capital investment proposed by the gas industry for liquid-based SNG plants should go instead, and as rapidly as possible into the construction of coal-based SNG plants.

Fourth, the NEP's goal that ". . . healthy economic growth must continue" [17] would be endangered by SNG production. Increased allocation of domestic liquid petroleum feedstocks to SNG plants will require more imports and raise prices to historical users such as petrochemical concerns, agricultural users, glass makers and steel makers who have no alternative feedstocks or process fuels. Reduced economic growth and a balance of payments deficit of billions of dollars could result. (See DEIS Exhibit 3.3-1.)

Fifth, we have projected that the net cost of SNG to the U.S. economy (see pp. 15-18 below) could finance conversion to coal of 30,000 to 241,000 barrels of oil equivalent, thus advancing rather than frustrating national energy goals. Taking into account a shift of the additional investment costs in SNG plants of $616 to

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[8] See Further Supplemental Comments of PEG, filed March 22, 1977.
[9] FEA Transcript, p. 60.
[10] *Id.*, pp. 61-62.
[11] Annual Report of the Brooklyn Union Gas Corporation to the State of New York Public Service Commission, p. G-47.
[12] FEA Transcript, p. 162.
[13] *Id* p. 162.
[14] NEP, p. 94.
[15] 10 C.F.R. § 211.29.
[16] 10 C.F.R. § 211.29.
[17] NEP, p. 26.

$1,576 million 1976 dollars to conversion to coal could decrease imports by another 73,000 to 186,000 barrels per day. Construction of the additional SNG plants would necessitate imports of 137,000 to 460,000 barrels per day. Thus, the total increase in equivalent oil imports due to additional investments in SNG plants is 210,000 to 646,000 barrels per day. See the table that follows:

Range of reductions in required energy imports from investing capital funds in coal conversion rather than SNG plants, 1980

Range of increased Capital investments in SNG plants under various options (millions of 1976 dollars)[1]	$616 to $1,576.
Range of capital costs for 250 MMBtu/Hr. coal boiler (millions of 1976 dollars)[2]	$9.1 to 18.
	73,000 to 186,000.
Range of increase oil imports under various SNG options (barrels per day)[3]	137,000 to 460,000.
Range of total reduction in energy imports from investing capital funds in coal conversion rather than SNG plants (barrels per day)	210,000 to 646,000.

[1] Page 6.0–5 of DEIS.
[2] The low end of range was taken from Table 4 page A–22 of "Replacing Oil and Gas With Coal and Other Fuels in the Industrial and Utility Sectors," Executive Office of the President, Energy Policy and Planning, June 2, 1977. An Adjustment to 1976 dollars (from 1975 dollars) was made. The high end of the range was taken from the April 1977 issue of Combustion magazine.
[3] Page ES–18 of DEIS.

Sixth, SNG production as proposed by the gas industry would be in sharp conflict with the NEP goal that "energy prices should generally reflect the true replacement cost of energy."[18] The DEIS clearly indicates that SNG demand will be greatly reduced if it is priced incrementally, and suggests[19] that the high cost of SNG even on a rolled-in basis, would reduce gas demand. At present, SNG is not priced at the cost of production. If it were, there is some doubt as to whether SNG would be marketable.[20] Even Section 414 of the National Energy Act does not propose to price SNG on a purely incremental basis, but rather would price it at a level not higher than alternate fuel costs, a price not reflecting its true cost.

Economic impact and employment implications

Increased SNG production will risk reductions in employment.

FEA's DEIS argues that since the rolled-in cost of SNG is cheaper than alternative fuels, increased SNG output has a positive effect on employment. Although this may be true if one averages costs for the Nation as a whole, it would not be the case in regions of the country where SNG would represent a significant portion of total gas supplies. More importantly, the cost of SNG can be disguised in gas industry rates but not to the economy as a whole. The DEIS only cites employment effects of lower cost, rolled-in SNG to industry. But if SNG production were increased, all other sectors—residential, commercial and electric utility—would be forced to pay higher prices by rolling in SNG costs so that, on balance, the negative impact on spending resulting from higher gas costs may more than offset the positive effect on industry through disguising the cost of SNG.

As can be seen from the table below, the net cost to the U.S. economy from SNG use as opposed to alternative fuel use ranges from $630 million under a continued case-by-case feedstock allocation policy to $2560 million with complete decontrol. Thus, it is difficult to claim that the rolling-in of SNG costs will have a positive impact on industry and employment.

[18] NEP, p. 29.
[19] DEIS, pp. 3.2–22 through 3.2–35.
[20] See PEG's Study Showing That SNG's Role In Preventing Curtailment of Residentials This Winter Has Been Overstated, at 14 and n. 23; PEG Testimony of John R. Ryan before the FEA (July 1, 1976), at 6.

	1980 SNG production (billion cubic feet)	Total cost of SNG[1]	Total cost of alternate fuels[2] (billions)	Net cost of SNG to U.S. economy (billions)
Base case	336.6	$1.77	$1.24	$0.63
Options:				
1. Case-by-case allocation	774.3	4.07	2.63	1.44
2. New plants limited to naphtha	774.3	4.07	2.63	1.44
3. Case-by-case NGL use, decontrol naphtha	1,200.6	6.30	4.08	2.22
4. NGL decontrol/case-by-case naphtha	956.2	5.02	3.25	1.77
5. Complete feedstock decontrol[3]	1,383.2	7.26	4.70	2.56

[1] Assuning an SNG cost of $5.25 per thousand cubic feet in 1980 dollars.
[2] Assuming average price of $3.40 per thousand cubic feet.
[3] See pp. ES 8-9, DEIS for full description of possible allocation options.

Note: Assumes all SNG production can be replaced by alternate fuels. In addition, no account has been taken of possible increases in SNG feedstock prices as a result of increased import requirements. It is assumed that any fuel cost savings to industry from the use of additional gas, in place of alternate fuels, made available as a result or decreased consumption induced by higher gas prices would be offset by the increases in SNG feedstock prices.

Source: Chart provided by Petroleum Indestry Research Associates.

Under optional changes in present SNG policy calling for either or both NGL and naphtha decontrol from price and allocation regulations, we project negative employment impacts since the prices of these products would rise. Despite the fact that naphtha is free from price and allocation controls, except for SNG use, increased naphtha demand would put upward pressures on naphtha prices. The volumes of naphtha available for sale in the world market is only a small fraction of the volumes of naphtha produced in refineries. Therefore, an increase in required naphtha imports into the United States on the order of several hundred thousand barrels per day could lead to a sharp jump in prices. For example, during the spring and early summer of 1973, gasoline imports into the United States increased on the order of only 100,000 barrels per day[21] and caused European spot prices in export markets to nearly double between mid-March and the end of May from 15 cents to 28 cents per gallon.[22]

In the case of LPG, the current differential between domestic and foreign overseas product is roughly 10 cents per gallon.[23] LPG decontrol would thus cause a precipitous increase in LPG prices to all consumers, since imported LPG would likely represent both a significant portion of U.S. supplies and the principal incremental supply source. Higher prices would, of course, have negative employment effects.

Also, if petrochemical companies experience a sustained shortage of feedstocks, there is a loss in jobs. Studies by Arthur D. Little[24] indicate that a 15 percent sustained reduction in feedstock supplies will result in a loss of 1.6–1.8 million jobs and $65–$70 billion loss in production values.

Balance of payments impact

The balance of payments effects of various policy options for increasing SNG production (based on the DEIS analysis) are shown below:[25]

DEIS options (see p. 16 for description)	Net import increase[1] (MM bbl.)	Addition to trade deficit	
		Million 1975 dollars	Million 1980 dollars
1	61	793	1,052
2	50	650	863
3	134	1,742	2,312
4	96	1,248	1,656
5	168	2,184	2,898

[1] Increments to the base case.

Note: Based on crude oil import cost of $13/barrel in 1975 dollars. The figures shown in 1980 dollars are based on our own calculations, assuming an average annual inflation rate of 5.8 percent.

[21] FEA, Monthly Energy Review October 1974, p. 12.
[22] Summary of European gasoline prices prepared from Platt's *Oilgram* Price Service.
[23] Cite Propane Butane News for the week ending July 5, 1977.
[24] Arthur D. Little, Inc., United States Petrochemical Industry Impact Analysis, November 1978.
[25] Chart provided by Petroleum Industry Research Associates.

The additional adverse effect (over the base use) on the U.S. balance of trade in 1980 ranges from $863 to $2,898 million under the various options. Since the cost of imported naphtha would likely be at least $2.50 per barrel above the cost of crude oil imports in 1980, as much as $200 to $300 million would be added to the trade deficits in Options 3 and 5, somewhat smaller amounts in the other options.

Naphtha supply and demand

The volume of naphtha for sale on the world market is only a small fraction of the volumes of naphtha produced in refineries, for refinery naphtha is most often used by the refinery for gasoline production or, increasingly, as petrochemical feedstock in the refiner's (usually a major integrated oil company) own petrochemical facility. Thus an increase in demand for imported naphtha of several hundred thousand barrels per day could significantly affect naphtha prices. Despite relatively low refinery operating rates in Western Europe and the Caribbean—averaging around 60 to 65 percent utilization in 1976[26]—the expansion of crude runs for incremental naphtha supplies poses a problem for these refineries since the marketplace is unlikely to be able to support increased output of the heavy end of the barrel.

More recent studies of the outlook for foreign naphtha agree that this product will be in relatively tight supply for the next ten years. This conclusion is based mainly on the naphtha outlook in Europe, the principal supply source and market for this product outside the U S.

For example, a recent study by the Institut Francais du Petrole[27] projected the following supply and demand balance for 1985 for the various products processed in European refineries:

WESTERN EUROPE PETROLEUM PRODUCTS SUPPLY AND DEMAND—1985

[Millions of metric tons]

	Output[1]	Demand	Difference
Naphtha	47.5	90	−42.5
Gasoline	115.5	128	−12.5
Jet fuel, kerosene	38.5	44	−5.5
Gasoil, deisel	278.5	255	+23.5
Residual fuel oil	342.5	290	+52.5
Other	72.5	88	−15.5
Total	895.0	895	

[1] Based on current refinery structure.

A somewhat similar conclusion is reached in a study by Trichen Consultants, Ltd., London, England, which shows European naphtha, moving from a small surplus in 1975 to a major deficits in 1985 if European ethylene feedstock requirements continue to be met by naphtha.

EUROPEAN ECONOMIC COMMUNITY NAPHTHA SUPPLY/DEMAND

	1965	1975	1980	1985
Growth rates, percent per year:				
Petroleum products			3.5	1.5
Petrochemical products			8.5	6.5
	Million tons			
Total crude oil processed	301.0	607.5	773.0	833.0
Total naphtha available	59.9	128.8	163.1	175.8
Naphtha for motor gasoline	36.1	56.7	63.0	62.0
Naphtha for other fuels	7.7	10.9	13.9	15.0
Naphtha for aromatics	4.5	20.4	36.1	49.5
Naphtha for other petrochemicals	2.5	4.5	4.6	4.6
Naphtha available for ethylene	9.1	35.7	44.7	43.8
Ethylene production	2.0	9.0	16.0	22.0
Naphtha required for ethylene	8.0	34.9	58.2	80.0
Naphtha surplus (deficit)	1.1	.8	(13.5)	(36.2)
Gas oil for ethylene to maintain naphtha balance	0	1.1	14.9	39.8

Source: Reprinted in Oil & Gas Journal, Aug. 2, 1976.

[26] Source: Petroleum Intelligence Weekly.
[27] Reported in Oil & Gas Journal, June 14, 1976.

As the bottom line of the table shows, the shortage can be alleviated if European ethylene plants turn to other feedstock, such as gas oil (distillate). However, this option applies largely only to new plants. It can be expected to reduce the deficit but not to eliminate it. Europe, which has historically been a small net exporter of naphtha, could thus become a net importer from the Caribbean and the Middle East.

A study by the consulting firm Jensen Associates, Boston, Massachusetts, undertaken jointly with the consulting firm Bonner & Moore Associates, Inc., Houston, Texas, concludes that:

1. No significant "surplus" of naphtha is expected to be available in either the U.S. or Europe during the period 1980–1985. However, additional increments of naphtha demand could be satisfied in either location during this period, at prices above those forecast for current demand.

2. Any substantial new demands for naphtha in the U.S. and Europe above those already projected for gasoline, jet fuel and petrochemical feedstock usage would result in significant naphtha price increases at both locations during the 1980–1985 period. European prices are forecast to rise more rapidly and to higher levels than U.S. prices.[28]

In 1976, PEG had occasion to address before FEA the issue of naphtha supply and demand on two different occasions.[29] That testimony is still timely and we incorporate it herein.

The Gordian Associates report prepared for FEA, "SNG Demand for Petroleum Feedstocks," generally supports the proposition that no excess of naphtha is in sight.[30]

One particular oversight in the FEA's DEIS Section on naphtha is the failure to recognize the unique position of the independent sector of the petrochemical industry. For example, the DEIS characterizes the naphtha problems to be one of price, not availability, since chemicals are only "produced in the refinery itself." (DEIS 3.2–57). That may be the case for an integrated petrochemical company, but that fact ignores the independent segment of the industry.

At another point, the DEIS alludes to a geographical advantage for petrochemical plants (DEIS, p. 3.2–57) vis a vis SNG plants. This notion does not adequately reflect the situation. We are aware of no geographical price advantage since imports would be needed to meet petrochemical industry demand. This need for imports would normalize any possible price differential. The advantage suggested in the DEIS might exist only where domestic supplies of naphtha are in surplus. Such a surplus has not been demonstrated.

LPG supply and demand

Continuing allocations of LPG to existing SNG plants or increasing them will endanger the supply and raise the cost of LPG for traditional high priority users. Considering the range of options proposed by the DEIS (varying from allocations only to the existing 13 plants to complete decontrol of SNG feedstocks) it is clear that the U.S. dependence on imports will substantially increase.[31]

Case	LPG for SNG, (M bbl/d)	Domestic production of LPG, (M bbl/d)	Percent
Base case	138	1,115	12
Option 1	204	1,115	18
Option 2	138	1,115	12
Option 3	211	1,115	19
Option 4	364	1,115	33
Option 5	366	1,115	33

This potentially high import growth raises serious problems of political and logistical barriers to adequate supply which pose risks to the national security and economic stability. For example, within the last six months, the Japanese have

[28] Jensen Associates, Inc., "Analysis of U.S. and European Naphtha Prices and Availability—1980–1985" (February 1976).

[29] See Testimony of Petrochemical Energy Group in "Exemption of Naphtha's, Gas Oils and 'Other Products' from the Mandatory Petroleum Allocation and Price Regulations," July 1, 1976. See also, testimony of PEG Witness Haaga in Baltimore Gas & Electric Co. Allocation of SNG Feedstocks. (Attached as Appendix A.)

[30] Gordian Associates, Inc., "SNG Demand for Petroleum Feedstocks," p. 2.

[31] Chart composited by PEG using DEIS data, p. 3.2–50.

moved to secure large supplies of LPG for use in electricity generation. We understand that present and projected terminal facilities on U.S. East and West Coasts appear inadequate to handle LPG imports. Some local port jurisdictions have indicated opposition to LPG ships or terminals and there may be a shortage of ships with sufficiently shallow drafts to enter many U.S. ports. Such factors need further study in the DEIS before any decision to increase SNG production based on them is made.[32]

Note that complete decontrol will result in an incerase in imports of LPG of 21% compared to the base case and would make imported LPG 33% of the total supply as compared to 29% in the base case. Further, the LPG consumed by SNG plants would equal 67 percent of total imports of LPG as compared to 30 percent in the case of continuing allocations only to existing plants. Obviously, national security is a significant concern whenever a policy is suggested that creates such a dependence on imports.

Higher import demand raises a third and closely related concern—the price of required LPG supplies. Increased U.S. imports of LPG will affect foreign LPG prices. Foreign LPG prices are largely administratively determined by OPEC countries, admittedly with an eye on the marketplace. Expanding U.S. imports are likely to trigger price increases because of, in general, the high value use of LPG in U.S. markets. Moreover, the U.S. market will be less price sensitive than other markets for foreign LPG use because there are fewer alternatives to LPG use by historic consumers.

The world LPG market is expected to be in relative balance over the next few years. Continuing the present level of SNG allocations results in imports of approximately 455 MB/D in 1980, and can probably be supported on the basis of likely new gas-processing facilities expected onstream in OPEC countries before 1980. Nevertheless, even this level of imports is likely to put upward pressure on foreign LPG prices.

Another supply related aspect of the analysis must be noted. The DEIS ignores the internal butane use in refineries, i.e., the butanes produced in the refinery directly consumed in refinery processing and gasoline blending. More than 70 percent of the total domestic supply of butane from refineries and extraction plants is used in refineries. This supply and/or use of butane could change dramatically with a number of possible changes such as refinery runs, types of crude processed, changes in gasoline specifications, such as octane, removal of lead from gasoline, changes in refinery processing, restrictions on aromatics and product imports. Such changes could drastically affect the balance resulting in changed demands for butane from non-refinery sources to the extent that available domestic supplies of butane could be diminished further.

An important finding of the FEA's DEIS studying options for incerasing SNG production, reveals that under any increase option, SNG production will actually replace some LPG, not to mention as much as 1.5 million tons of coal.[33] Such a result is not only in direct conflict with the goals of the NEP, it has the anomalous effect of allowing SNG production from LPG at a net loss of energy to replace the LPG itself.

This result obtains even though the DEIS study does not even include the potential demand for propane for Btu enrichment in SNG plants. It states that the demand can be large[34] yet it fails to provide any information on projected quantities required. It says in its discussion on the thermal efficiency of SNG plants that the SNG has a heating value of 977 Btu per Cf and no facilities are shown for Btu enrichment in its flow sheets. Yet we know from the applications for propane and butane allocations for Btu enrichment from SNG plants that large quantities of propane and butane are required and that the heating value of SNG can be much lower.[35] Since propane and butane are being used for Btu enrichment regardless of the named feedstock, the demand projected in the DEIS options is lower than it will actually be.

II.

NO NEED HAS BEEN SHOWN FOR EXISTING SNG CAPACITY OR FOR ADDITIONAL PRODUCTION

No need for present facilities—even last winter

We have searched in vain for evidence that the "13 SNG plants that were operating this winter provided the additional margin of natural gas supply that

[32] In contrast, note risks cited in DEIS with respect to LNG imports, p. 7.2-26—7.2-29.
[33] DEIS, p. 8.2-80.
[34] DEIS, p. 2.2-4.
[35] See Applications before the FEA for Btu enrichment by Northern Illinois Gas Company and Brooklyn Union.

kept several areas of the country from shutting off residential users during the coldest months." (National Energy Plan, p. 57). Our study of this issue is detailed in Appendix C (excepting, of course, a plant in Hawaii). Examples from that study follow:

Brooklyn Union Gas Company.—Brooklyn Union testified last week at an FEA hearing that it used SNG last winter to supply higher than normal demand but made no effort to buy emergency gas under ENGA at $2.25 per Mcf. Its cost of SNG is reported as $3.24 per Mcf.[36] and short-term sales of SNG have been made at prices ranging between $4.00 and $5.09 per Mcf.[37]

The overall experience of Brooklyn Union indicates no need for SNG. In 1976, it attached an additional 3,294 residential space heating customers.[38] It has continued to sell gas to interruptible industrial customers, 2.3 Bcf in 1976.[39] 1976 sales to firm industrial customers amounted to 4.5 Bcf.[40] Brooklyn Union has projected gas supply surpluses over requirements of 16.9 Bcf for 1977–1978; 17.6 Bcf in 1978–1979; and 15.9 Bcf in 1979–1980.[41] These volumes are in excess of the maximum capacity of Brooklyn Union's SNG plant (10.8 Bcf for a 180-day winter heating season).[42]

Consumers Power Company.—Last winter, Consumers had no shortage of gas for high priorities. It continued boiler fuel sales and apparently did not curtail any of its customers, including those in FPC categories 4 and 5.[43] FPC Form 423 filed by Consumers for November through March 1977, reveals that Consumers sold 4.9 Bcf during this period for electrical generation. This, of course, was during Consumers' peak requirements period. Consumers' peak day for deliveries was in December of 1976 and the consecutive three-day peak was in January 1977.

Nor did Consumers need SNG production at any time last year. In July 1976, Consumers estimated it would deliver 33.33 Bcf during 1976 to customers in FPC categories 4 through 9, i.e. the boiler fuel categories.[44] It appears that at least 30.6 Bcf of this gas was sold to customers under a "seasonal" rate schedule which allows 90 day interruption. (Appendix C, pp. 3 and 4) Consumers also sold 6.2 Bcf to itself, primarily for electrical and steam generation.[45] Thus, last year Consumers sold at least 36.9 Bcf to customers with boiler fuel uses or to those whose rate schedules indicate alternate fuel capability. The full production of Consumers' SNG plant in 1976 was 59.3 Bcf.[46] Overall, the figures submitted to the Michigan Public Service Commission by Consumers show that its total 1976 gas supply exceeded its 1976 demand by 71.1 Bcf.[47] Thus, it is clear that the SNG plant capacity was not needed during 1976, yet customers on the system paid for 59.3 Bcf of SNG which Consumers itself estimates costs $3.50 per Mcf.[48]

Information regarding the lack of need for SNG production, both this past winter and generally, for Columbia and Northern Illinois Gas have been discussed previously. I would urge this panel to consider PEG's Appendix A in full before making any decision regarding the need for a change in its policy toward SNG facilities.

For the future, other supply options are preferable

The National Energy Plan bases the need for increased SNG production on a requirement for increased supplies of natural gas to meet "critical peakload needs

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[36] Annual Report, p. G–47.

[37] *See, e.g.*, Contracts between Brooklyn Union and Piedmont Natural Gas Company, Inc., dated Jan. 11, 1977; Brooklyn Union and South Jersey Gas Co., dated Jan. 22, 1977; Brooklyn Union and Philadelphia Electric Co., dated Mar. 1, 1977; and Brooklyn Union and Pavilion Natural Gas Co., dated Feb. 9, 1977. (These contracts are included as Exhibits 5A, B, C, and D, of the Full Study of Last Winter's Gas Shortage, submitted by PEG to FEA.)

[38] Annual Report, p. G–11.

[39] *Id.*

[40] *Id.*

[41] New York 1976 Gas Reports.

[42] AGA, *Gas Supply Review*, Summary of SNG-From-Petroleum Plants (January 1977); New York 76 Gas Report (Prepared for New York State Public Service Commission by NY Gas Planning Committee In Compliance With Case 25766).

[43] "Rebuttal Comments of Consumers Power Company," at p. 6, filed with FEA's Office Office of Regulatory Programs, November 1976.

[44] Attachment II to a letter dated July 13, 1976 to Mr. Gorman C. Smith, Assistant Administrator, Regulatory Programs, FEA, from O. K. Petersen, Esquire, Managing Attorney for Consumers Power Company.

[45] Consumers Power Company Annual Report to the Michigan Public Service Commission for the Year Ended December 31, 1976, at p. 523.

[46] *Id.* at pp. 563 and 518d, line 10, column (3).

[47] Appendix C, pp. 4–5.

[48] "Rebuttal Comments of Consumers Power Co.," at p. 19, filed with FEA's Office of Regulatory Programs, November 1976.

for gas over the next 5 to 7 years."[49] Yet to the extent there will be a future need for gas supplies, other options are preferable. We believe that reasonable estimates of gas supply and demand indicate SNG will not be required.

Among the factors that must be taken into account in estimating need for SNG in 1980 and beyond are: (1) higher interstate gas prices set in mid-1976 and the current FPC proceedings to review and revise that rate; (2) the FEA coal conversion program; (3) emergency sales possibilities under FPC regulations and emergency legislation such as the Emergency Natural Gas Act of 1977 (ENGA) which the President proposes to extend;[50] (4) state, federal and private, voluntary conservation programs. Further, emerging energy policies must be included, e.g., an accelerated coal conversion program, use taxes on natural gas, and home and transportation conservation proposals. Favorable supply trends, including the prospects for Mexican gas exports to the United States, OCS gas and Alaskan gas must be considered. (Most of these factors were ignored or improperly calculated in the DEIS.) Management of pipeline gas supplies to eliminate boiler fuel uses and to increase pipeline storage facilities will also yield substantial savings. When these factors are taken into account, the claimed requirement for SNG vanishes.

Price factors

A recent analysis by the Federal Energy Administration (FEA) in its 1977 draft report, National Energy Outlook, circulated for comments in January 1977 and parially revised in February 1977, indicates that continued FPC Opinion 770, (which established the new interstate rate) would result in domestic conventional gas production of 16.9 Tcf in 1980.[51] Assuming this level of gas production and the level of supplementary sources of gas estimated in the DEIS, available gas supply would be 18.09 Tcf in 1980 as shown below:

1980 available gas supply (Tcf) reflecting FPC opinion 770

LNG	0.95
SNG	0.34
Pipeline imports [1]	1.00
Available conventional domestic supply [2]	15.80
Total	18.09

[1] From Canada.
[2] Excludes NGL extraction and other losses.

Source: 1977 National Energy Outlook.

The effect of the President's National Energy Plan must also be considered. The Plan estimates that 17.4 trillion cubic feet will be produced in 1985 (NEP, p. 96) (converting barrels equivalent to Tcf), while demand will be cut by 1.5 Tcf (NEP, p. 95). The House Commerce Committee has just adopted the President's Plan.

Legislation is still pending to terminate federal price controls on new natural gas. An ERDA witness just testified before a House Subcommittee that, at $3.00 per Mcf, there would be sufficient gas to meet all demand in 1985. (Oral Testimony of Dr. Harry R. Johnson, Deputy Assistant Administrator, ERDA, before Subcommittee on Fossil and Nuclear Energy Research, Development and Demonstration, House Committee on Science and Technology, July 12, 1977.)

Other new sources of supply

New supplies from Alaska and the Atlantic OCS will be important factors in the 1980–1985 period,[52] the time new SNG plants would be coming on line. In terms of efficiency and supply security, these sources would be preferable.

Recent data indicates Mexico is finding gas to oil ratios in the range of 6000:1 in the Reforma fields. Petroleos Mexicano, the state oil company, is now pushing for a 48'' line to the U.S. to export up to .7 Tcf/year by 1982.[53] This is a source of gas that would be available in the same time frame as SNG from new plants.

Since the case for SNG is largely based on the need to protect high priority users during periods of especially high demand similar to last winter's shortage situation, one must consider the supply impact of legislative provisions similar

[49] NEP, p. 58.
[50] P.L. 95–2.
[51] *National Energy Outlook,* Table V–12 of 1977 draft report.
[52] DEIS, p. 7.2–14.
[53] *Oil and Gas Journal,* June 27, 1977, pp. 63–65.

to those of the Emergency Natural Gas Act of 1976.[54] This Act successfully countered emergency shortage situations in the interstate market[55] through allowing limited term, non-jurisdictional sales by producers and intrastate pipelines. The Congress is considering an extension of ENGA, with and without modification.

Both existing and proposed conversion and conservation programs will also have a major impact on gas demand.

For example, on June 30, 1977, FEA issued prohibition and construction orders under its ESECA program estimated to save 14 Bcf of gas per year.[56]

Also, recently the FEA issued final conservation targets for ten energy intensive industries in its mandatory conservation reporting program.[57]

In addition, the President projects gas savings of 3.6 Tcf per year in 1985 if all provisions of his coal conversion program are enacted.[58] Savings in electric utility gas consumption alone would equal 2.3 Tcf per year by 1985 if the President's program were enacted.[59] Since total industrial gas consumption in 1985 has been projected to be 11.3 Tcf[60] the savings from enactment of the total program represent a reduction in industrial demand for natural gas of approximately 32 percent.

Thus, even if state and voluntary conservation and coal conversion plans are ignored, it is clear that mandatory existing and prospective policies will have a significant restraining effect on natural gas demand.

Proper management of existing gas supplies is the most efficient, quickest, and surest way to protect high priority consumers. During 1976, some 656.3[61] Bcf of gas in the interstate market was burned under electric utility boilers purchasing through interruptible contracts. The ability to purchase interruptible gas indicates that these purchasers have alternate fuel capability. Even during last winter's natural gas crisis, 103.6[62] Bcf of gas was burned under interruptible contracts. Thus, if all of the interstate natural gas which was sold in 1976 under interruptible contracts had been diverted to high priority users instead, the resultant yield would have been almost twice the available amount of SNG projected for 1980. The fact is, every year billions of cubic feet of natural gas are being wasted in facilities that can use alternate fuels. Proper management of this gas can provide security as early as next winter to high priority consumers. This degree of security can be increased as pipelines and distributors develop more extensive storage capacity so that gas available in the summer, rather than being dumped under interruptible boilers, can be held in reserve for unusual conditions.

Finally, the use of propane-air plants could provide a large measure of additional gas supply while avoiding the inefficiencies and waste of using propane to manufacture SNG. Propane-air plants are far less expensive to build than SNG facilities, they can be readily switched on and off for peaking, and the efficiency of use approaches 100 percent. To the degree that supplemental supplies are needed, propane-air plants provide an efficient, rapidly available means of increasing gas supplies without subjecting consumers to 20 to 30 years of SNG costs whose output is not needed year round or over the long term.

It is important to note that the factors mentioned above were not considered in FEA's SNG DEIS, resulting in very unrealistic supply/demand projections. Supplies of gas from non-SNG sources will be more than adequate to protect high priority users through 1985. In the absence of hard evidence to counterbalance these indications, it would be a grave mistake to move now to increase SNG production. This is particularly true in view of the risks to national security, costs to the economy and to high priority consumers, and detriment to implementing a rational energy plan for the nation that would be incurred by

[54] P.L. 95–2, February 2, 1977.

[55] Statement of Administrator R. A. Dunham before the Subcommittee on Energy and Power, Committee on Interstate & Foreign Commerce, U.S. House of Representatives, April 5, 1977.

[56] FEA News Release #E77–212, June 30, 1977.

[57] 42 Fed. Reg. 29642, June 9, 1977.

[58] "Replacing Oil and Gas with Coal and Other Fuels in the Industrial and Utility Sectors," Executive Office of the President, Energy Policy and Planning, June 2, 1977, p. 4.

[59] *Id.* at II–2.

[60] *Id.* at Table I, A6–7.

[61] FPC News, Vol. 10 No. 2, January 14, 1977, at Table 11; FPC News Release No. 23271, July 12, 1977, at Table 11.

[62] FPC News Release No. 23271, July 12, 1977, at Table 11. Figures include gas purchased under interruptible contracts in the interstate market for the months November 1976 through February 1977, inclusive.

changing SNG policy. In the years beyond 1985, of course, we can look to coal-based SNG and a substantial impact from coal conversion programs to safeguard the needs of high priority consumers.

III.

PROPOSED ALLOCATION CRITERIA

FEA has asked several questions, Numbers 5, 14, and 15, relating to criteria to be applied to SNG feedstock allocations.

The criteria discussed below should be applied to both existing and new applications for SNG feedstock allocations. Such standards are necessary to protect the consumer and to ensure rational energy planning for the Nation.

Based on the discussion in parts I and II above it is fair to conclude: (a) that allocation of precious, clean natural gas liquids and naphtha for consumption in SNG plants would be a wasteful use of scarce energy resources for which there are many alternatives. (b) Use of alternatives would have a less harmful impact on supply, price, the economy, and the environment. (c) Allocation of natural gas liquids and naphtha to SNG plants will force all consumers of those products to collectively increase their dependence on insecure imports with adverse impacts on price, competitiveness of domestic industry, and the U.S. balance of trade. (d) Allocation of natural gas liquids and naphtha to SNG plants is inconsistent with virtually all tenets of the National Energy Plan. (e) In most instances, available information indicates the SNG is not needed now nor will it be needed in the future to protect high-priority residential users of natural gas.

We believe that FEA studies, including the DEIS recently issued for public comment establish these points. We continue to wait for those in the gas industry who actually have end use data, to come forward with facts and figures to support their claim that SNG is needed for high priority users now or in the future. We continue to wait for evidence that even a single one of the 18 existing SNG plants in the continental U.S. was needed to prevent curtailment of high priority users last winter. The publicly available data, compiled by PEG and attached as part of this testimony, shows instead that expensive SNG has been used in preference to cheaper more efficient alternatives such as emergency purchases under ENGA, pipeline gas, storage capacity, or curtailment of boiler fuel users with alternate fuel capability—both during this winter's severe weather and generally as a matter of routine company practice.

Should there be a clear showing of special circumstances under which SNG production could serve as a short-term means of protecting high priority users, FEA must take careful precautions to protect the consumer.

We would recommend the following procedures and criteria to accomplish this:

(1) Each application for a new facility should be considered individually by FEA.

(2) Allocations for existing facilities should not extend beyond a one year period so that compliance with FEA's regulations can be insured. The record in the individual cases indicates numerous violations of allocation orders by existing SNG plants.

(3) SNG should not be used for foster growth and attachment of new customers.

(4) SNG should not be produced when the pipeline or distributor it serves is selling gas for boiler fuel.

(5) SNG should not be produced until all alternatives of pipeline and distribution companies such as storage of summer supplies of gas. LNG, gas from Mexico, increased producer deliveries, curtailment of low priority sale and emergency procedures have been exhausted.

(6) SNG should be priced on an incremental basis to the end user.

(7) SNG plants should be financed on a maximum basis of 10 years.

APPENDIX A

STATEMENT OF DONALD A. CENTER

Mr. Chairman, members of the panel, I am Donald A. Center and I am Supply Manager—Liquid Feedstocks and Energy at Union Carbide Corporation. We are a large petrochemical feedstock user of naphtha and I am responsible for purchasing that product for Union Carbide. As you have heard from Joan Ryan, we are in strong support of the FEA's proposal to exempt naphtha, gas oil and other products from allocation and price controls, with one exception. That one exception—allocation of naphtha to *liquid-based SNG plants*—is necessary, we believe, to ensure the effective and lasting implementation of the proposed naphtha exemption. We have reviewed FEA's *Preliminary Findings and Views*[1] and other assessments[2] of the present and projected supply and demand situation for naphtha and believe that these studies provide the factual basis in support of the SNG exception.

We have reached four general conclusions:

1. There is no present or long-term "surplus" of naptha in either the domestic or world markets;

2. Adequate naphtha supplies are essential to the continuing viability of the independent sector of the U.S. petrochemical industry;

3. Unjustified allocations of naphtha to large-scale, inefficient and non-essential users such as to new SNG plants proposed by gas utilities can only result in either increased diversion of domestic supplies from historical users including the petrochemical industry, or the increased dependence of high priority natural gas users on foreign sources.

4. A massive, new naphtha demand from SNG manufacturers will adversely affect the adequacy of assured and economic supplies of naptha to our industry.

NAPHTHA SUPPLY AND DEMAND

As FEA's Preliminary Findings accurately describes, current U.S. naphtha requirements are directly related to domestic demands for gasoline and petrochemicals. Historically, more than 90 percent of U.S. naphtha has gone to the pool of products used to blend motor gasoline; the balance has largely been used to make aromatics and olefin-based petrochemicals.[3] Imported foreign naphtha has been and will continue to be used to a relatively minor degree in U.S. gasoline manufacture; however, about 40 percent of U.S. motor gasoline is now made from imported crude.[4] Approximately 20 percent of U.S. ethylene production is currently dependent on imported petroleum as shown in Table 1. Thus, any increased demand even for gasoline and/or petrochemicals will substantially increase imports and U.S. dependence upon foreign sources for these products. As the Jensen Report indicates:[5] "In the United States, naphtha will remain in limited supply and will be priced in accordance with gasoline values."

In its Preliminary Findings, FEA concludes that naphtha is and will continue to be in adequate supply, but states that difficulties in satisfying the demand for gasoline can have a significant impact on the supply of naphtha[6] and that "implicit" in the conclusion that naphtha supplies (domestic and imported) in 1976, 1977 and 1978 are sufficient to meet petrochemical feedstock requirements is the assumption that sufficient supplies of naphtha will also be available to meet gasoline production demand.[7]

Further review of the data in FEA's Preliminary Findings indicates that net naphtha imports to the U.S. are expected to *decline* from 141 MBPCD in 1973 to 140 MBPCD in 1977. In addition, forecasted naphtha demand in the U.S. is projected to decline from 4462 MBPCD to 4455 MBPCD. We find this surprising in view of the forecasted increase in SNG demand, the forecasted increase in gasoline demand,[8] the necessary increase in demand for petrochemical feed-

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[1] FEA, "Preliminary Findings and Views Concerning the Exemption of Naphtha, Gas Oil, and 'Other Products' from the Mandatory Petroleum Allocation and Price Regulations," Washington, D.C. (June 4, 1976). (Preliminary Findings)

[2] Notably, Jensen Associates, Inc., "Analysis of U.S. and European Naphtha Prices and Availability—1980–1985" (February 1976). (Jensen Report)

[3] Preliminary Findings, pp. 104 and 264.

[4] See FEA, "Monthly Energy Review," May 1976, p. 5 *et seq.*

[5] See Jensen Report which incorporates Bonner & Moore Associates, Inc., "Analysis of Future Naphtha Price and Availability," 20 February 1976, p. A–2. (B&M Report).

[6] Preliminary Findings, pp. 45 and 131.

[7] Preliminary Findings, p. 262.

[8] The Jensen Report at p. 2 concludes that: "Some excess naphtha (or gasoline) production capacity appears available in U.S. refineries now and between now and 1980. This capacity has become available because both crude processing and conversion capacities have increased substantially since 1973 while crude runs and gasoline prodution have not." Compare, however, FEA "Demand Watch" dated June 24, 1976 (Release No. E-76-161) and FEA, "Monthly Energy Review." For the week ended June 18, 1976, operable refinery capacity was utilized at a rate of 93.3% compared with 84.6% during the week ended June 20, 1975 (API, Weekly Statistical Bulletin, Vol. 57, No. 1).

Similarly, at p. 240, FEA projects a more than 10% increase in motor gasoline demand between 1975 and 1978.

stock,[9] and the forecasted decline in total supply. These facts cast doubt upon the accuracy of FEA's conclusion. We have concluded that the increased naphtha demand will require increased imports as measured between 1973 and 1977 and beyond.[10] In addition, we believe that in limiting the forecast period to 1978, FEA distorts the true impact of new SNG demand, both as to price and supply, especially in view of the fact that once SNG plants are built and supply commitments are made, the impact is long-lived and essentially irreversible.

FEA's Preliminary Findings, which state that "no inequitable prices for any class of user should result from exemption" overlooks FEA's own price impact findings at p. 323 and the conclusion reached in the Jensen Report that:

"Any substantial new demands for naphtha in the U.S. and Europe above those already projected for gasoline, jet fuel and petrochemical feedstock usage would result in significant naphtha price increases at both locations during the 1980–1985 period. European prices are forecast to rise more rapidly and to higher levels than U.S. prices."

We conclude—and our buying experience teaches us—that competition for world supplies of naphtha will increase in intensity and complexity.[11] World supplies of straight run naphtha are currently limited due to reduced fuel oil demand and corresponding reductions in refinery operations. Middle East sources are as insecure today as they were in the early 1970's, and Far Eastern supplies are economically illogical because of shipping costs. Caribbean refineries, from which U.S. petrochemical plants, including those of Union Carbide, have traditionally obtained most of their supplies, remain the most logical and economical source for imported naphtha. Even there, however, early reversion of crude processing rights to the Venezuelan government has disrupted some Caribbean sources.

While FEA implies in its Preliminary Findings that "surpluses" of motor gasoline indicate the potential for naphtha surpluses,[12] there is no current or projected "surplus" of domestic or foreign naphtha. FEA's demand forecast would tend to agree.[13] Moreover, any limitation upon non-essential demand to the point where potential supply exceeds potential demand has the beneficial effect of potentially decreasing crude runs and imports. On the other hand, a massive new demand for naphtha from SNG users will have a significant adverse effect upon the availability and adequacy of economic supplies of naphtha to existing users, including the petrochemical industry.

The U.S. has traditionally depended upon offshore naphtha directly and indirectly through refining of imported crude[14] to meet a substantial part of the naphtha requirements of existing users, this dependence is likely to increase in the future. If offshore naphtha supplies are made available to meet any increase in U.S. demand, whether or not at the expense of existing foreign users, they will be available only at a considerable increase in cost.

THE PETROCHEMICAL INDUSTRY'S DEPENDENCE ON NAPHTHA

As new petrochemical capacity is constructed in the U.S., there will be increasing dependence on naphtha and other petroleum liquids due to decreasing availability of feedstocks from natural gas processing.[15] Of the 12 new ethylene plants scheduled to be on stream by the early 1980's, we believe that all but two will use refinery source feedstocks, including naphtha. We estimate a shift in the type of feedstocks for making ethylene to the point where naphtha will constitute about 50 percent of U.S. ethylene raw materials by 1980. (See Table 2.) Aromatics growth will add to this feedstock demand.

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[9] See Preliminary Findings, p. 92. The B&M Report states at p. A–2 that:

"Predictions of future naphtha demands, and therefore prices, show strong growth patterns based solely on petrochemical feedstock needs. In fact, current thinking about expanded uses of plastics in automobiles suggests that future petrochemical feedstock needs may even be under estimated."

[10] For example, at p. 268, FEA states:

"Although little effect on naphtha supplies is expected during the two-year forecast period because of the length of time required to design and construct a new naphtha-fed SNG plant, it appears that increased use by 1980 could, at a maximum, exceed MB/D and entail a total investment of some $1.1 billion for naphtha-fed SNG plants alone. If the maximum possible use materialized, national vulnerability to a future embargo-related shortage would be considerably increased."

[11] The Jensen Report at p. 3 concludes: "Between 1976 and 1980, spplies of naphtha in Europe are expected to remain tight with prices at or near the historic high levels being experienced now and projected for 1980."

[12] Preliminary Findings, p. 234.

[13] See, e.g., Preliminary Findings, p. 264.

[14] See Table I.

[15] This is reflected at pp. 87, *et seq.* of the Preliminary Findings.

Looking ahead one can clearly see a tight naphtha supply situation facing petrochemical and other consumers. Acute shortages prevailing during the first part of 1974 have disappeared primarily because of the deep recession that has been affecting the world petrochemical industry, as well as economic activity generally. The sharp drop in petrochemical demand in 1974 and 1975 more than offset the increasing naphtha requirements of the gasoline market and the decreasing supplies due to declining world-wide crude runs, thereby creating the appearance of a naphtha "surplus."

However, a reversal of this situation is now taking place due to increased economic activity and surging gasoline consumption. The result will be a continuing and growing U.S. naphtha supply deficit. To date, Caribbean refineries have supplied the bulk of the U.S. naphtha shortfall, but some additional supplies will have to come from the Mediterranean and the Middle East. Although we are finding small amounts of low-octane raffinate and light straight run naphtha in the U.S. market, indicative of changes in the U.S. gasoline pool due to no-lead gasoline, unquestionably the bulk of this naphtha shortfall will be supplied at higher cost from foreign sources, since sizeable volumes are not available to non-integrated buyers from domestic refineries where the conversion of crude oil to gasoline is generally at a high level.

If we are to meet the nonsubstituable demands of our customers and to avoid the petrochemical shortages that occurred in the past, it is essential that adequate and economic supplies of naphtha be made available for petrochemical feedstock use. The economic consequencies of failing to meet that demand will reverberate through the economy. Chapter VII of FEA's Preliminary Findings reflects this fact, as well as the fact that while naphtha and other products used as petrochemical feedstocks are not a major source of revenue to refiners, "the economic value of some of these products is disproportionately large because they serve as critical feedstocks for such diverse groups of raw materials as synthetic rubber, synthetic fibers, plastics, and resins, which are, in turn, manufactured into such finished products as apparel, tires and innertubes, and transportation equipment." [16] We compete in world markets, and to meet demand, either the products are produced here in the U.S. or they are imported at more than 20 times the cost of the raw materials imported to make petrochemicals.

CONCLUSION

In summary, we draw three conclusions:

(1) While adequate supplies of naphtha may now be available to U.S. consumers, there is no present or long-term "surplus" of economically competitive naphtha in either domestic or world markets.

(2) Removing all restrictions on the use of naphtha in SNG plants will either divert naphtha from domestic supplies which are inadequate to meet the requirements of existing users, including PEG companies; or massively increase the price and supply dependency of the country on foreign sources.

(3) Adequate and economic supplies of naphtha from either domestic or foreign sources are essential to the continued viability of the independent sector of the petrochemical industry. That viability, as well as the objective of reducing dependence upon foreign energy sources, is jeopardized by the diversion of naphtha to new, wasteful and unnecessary uses.

Thus, we have concluded that sound public policy would call for the removal of price and allocation controls as to all products proposed for exemption so long as there is a continued limitation on naphtha used as SNG feedstock.

Thank you.

TABLE 1.—SOURCE OF FEEDSTOCKS BY GEOGRAPHICAL SOURCE FOR UNITED STATES AND PUERTO RICAN ETHYLENE PRODUCTION

[In percent]

	1970	1975	198
U.S. domestic	95	80	70
Foreign imports (product and crude)	5	20	30

[16] See p. 200. Analyses by independent consultants, confirmed during the recent recession, indicate that a sustained 15 percent reduction in the output of the organic chemicals industry could result in a loss of 1.6 to 1.8 million jobs in consuming industries and a loss of domestic production value of $65–70 billion annually. See Arthur D. Little, Inc., "U.S. Petrochemical Industry Impact Analysis," November, 1973.

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TABLE 2.—SOURCE OF FEEDSTOCKS FOR UNITED STATES AND PUERTO RICAN ETHYLENE PRODUCTION

[In percent]

	1970	1975	1980
Gas liquids (ethane, propane, butane)	88	76	50
Heavy liquids	12	24	50

Source: Petrochemical energy group.

APPENDIX B

The DEIS provides a detailed analysis of thermal efficiencies for SNG and alternative energy sources, consisting of alternative sources of natural gas, alternative methods of synthesizing gas, and use of substitute fuels, specifically, coal, oil, and electricity. The inefficiency of the conversion of liquid hydrocarbons to SNG is clearly illustrated by the DEIS calculations.

Exhibit 2.5–11 details the thermal efficiency percentages of SNG production from the various feedstock. Exhibit 5.11:

THERMAL EFFICIENCY OF TOTAL SNG TRAJECTORY PRIOR TO END USE

Trajectory	Primary efficiency (percent)	Ancillary energy (10^9 Btu^9/10^{12} Btu)	Overall efficiency (percent)
Domestic onshore naphtha	95.4	133.6	83.7
Domestic offshore naphtha	95.4	145.3	82.9
Canadian crude naphtha	95.4	134.4	83.7
Middle East crude naphtha	95.3	160.4	81.4
Domestic NGL	90.5	96.4	82.6
Domestic onshore LPG	96.5	145.0	83.8
Imported LPG	96.4	149.0	83.3

Exhibit 8.1–1 indicates the thermal efficiencies of several alternative sources of natural gas. Clearly, the most efficient of the alternative sources are import of LNG and offshore gas production. Exhibit 8.1–1:

THERMAL EFFICIENCY FOR ALTERNATIVE SOURCES OF NATURAL GAS BEFORE END USE

Trajectory	Primary efficiency (percent)	Ancillary energy (10^9 Btu/10^9 Btu)	Overall efficiency (percent)
Alaskan natural gas pipeline (Arctic gas)	78.5	0	78.5
Alaskan natural gas pipeline and LNG tankers (El Paso Gas)	63.5	15.4	60.1
Offshore natural gas	85.4	0	85.4
Imported LNG	91.7	27.8	89.2

Exhibit 8.1–2 tabulates the overall trajectory thermal efficiency for alternative methods of synthesizing natural gas. Exhibit 8.1–2:

THERMAL EFFICIENCY FOR ALTERNATIVE METHODS OF SYNTHESIZING GAS BEFORE END USE

Trajectory	Primary efficiency (percent)	Ancillary energy (10^9 Btu/10^9 Btu)	Overall efficiency (percent)
Lurgi high-Btu coal gasification	51.4	2.2	51.2
Synthane high-Btu coal gasification	49.5	2.3	49.3
Lurgi low-Btu coal gasification	71.7	27.8	68.9
Gas from crude oil	81.6	43.8	77.2
Gas from oil shale (TOSCO II processing)	43.7	4.8	43.2
Gas from solid waste (bioconversion)	58.9	43.0	54.6
SNG from naphtha feedstock [1]	95.4	133.6	83.7
SNG from LPG feedstock [1]	96.5	145.0	83.8

[1] Naphtha and LPG produced from domestic onshore crude oil.

Exhibit 8.1–3 depicts the comparative thermal efficiency calculations for substitute fuels. Exhibit 8.1–3:

THERMAL EFFICIENCY FOR SUBSTITUTE FUELS BEFORE END USE

Tajectory	Primary efficiency (percent)	Ancillary energy (10^9 Btu/10^{12} Btu)	Overall efficiency (percent)
Coal and refined petroleum products:			
Coal	69.0–75.0	84.0	61.0–67.0
Distillate fuel oil	98.8	115.2	87.2
Imported LPG	99.5	57.8	93.8
Electricity:			
Coal powerplant	(1)	(1)	25.1
Residual fuel oil powerplant	35.5	167.1	29.8
Nuclear LWR	22.0	88.5	19.5
Nuclear HTGR	(1)	(1)	22.5
Nuclear LMFBR	(1)	(1)	34.3

[1] Not available.

The foregoing exhibits graphically demonstrate the inefficiency of conversion of liquid hydrocarbons to SNG, but the calculations represent the process as significantly more efficient than it is in actuality. The analysis omitted consideration of several significant alternatives that must be examined before accurate calculations can be demonstrated. Deficiencies in the DEIS analysis include the following items:

First, the conversion of electrical energy consumed by the process is calculated at thermodynamic parity. (DEIS, p. 2.5–10, 11). The evaluation of the actual efficiency of any energy trajectory should include the fuel consumption involved in producing the electricity and its resultant impacts. Extrapolating from the electrical trajectories in the DEIS, we would expect four times the energy consumption for electrical energy production.

Second, it would appear that the energy consumption involved in the processing of fuel for hydrogen generation, the operation of environmental protection systems such as sulphur removal, cooling water system operation, etc. was not included in the analysis. This omission would mean that SNG efficiency is significantly less.

Third, the technique for calculating efficiencies employs "high heating values" in determining process efficiency. Use of fuel "high heat values" assumes that in the subsequent energy conversion steps employing SNG, the heat released by combustion that is to be recovered, includes the heat of condensation of water produced in the processes of combusting SNG. In actuality, condensation is avoided in conversion processes to reduce corrosion. Although this problem is discussed in Page 8.2–1 of the DEIS, consuming processes are computed with "high heating values"; therefore, there are problems in attempting to normalize the performance of the competing fuel use processes. In order to eliminate this factor in calculating conversion process efficiency, the efficiency computation should employ the "low heating" value figure (where heat released by moisture condensation is not included). Use of the "low heating value," therefore, provides a better, more realistic appraisal of energy recovery expectation when comparing combustion and conversion processes employing alternative fuels. Correcting the SNG process efficiency computation to a low heat value basis, which appropriately normalizes this efficiency calculation, will further reduce the efficiency appraisal of converting liquid hydrocarbons to SNG.

The inclusion of these considerations and the normal operating inefficiencies encountered would establish that efficiencies of converting liquid hydrocarbons to SNG at efficiencies greater than 85% would be exceptional and 80% might be more typical of net efficiency actually experienced. The DEIS correctly portrays the unnecessary energy degradation involved with employing SNG in energy trajectories with the resultant unnecessary resource, economic and environmental waste, but fails to accurately portray the magnitude of the inefficiency.

APPENDIX C

SNG's Role in Preventing Curtailment of Residentials This Winter Has Been Overstated

INTRODUCTION

This study is to reaffirm that there is no evidence to support the statement on page 57 of the National Energy Plan [1] that Synthetic Natural Gas (SNG) made from liquid hydrocarbons at the 13 SNG plants operating this winter was needed to provide the margin of gas supply that kept residentials from being shut off. PEG has requested information by letter to Administrator O'Leary dated May 19, 1977, that supports that claim but has yet to receive such information.

On our own in the limited time since the National Energy Plan was announced, PEG has made its own inquiries and has found no evidence that: ". . . the 13 SNG plants operating that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months."

Instead, we have found that some companies with SNG plants were increasing their loads, selling gas for electric generation, deferring gas deliveries until summer, or not curtailing any customers at all. Far from being the margin of safety for residentials, much SNG production serviced low priority and interruptible uses.

As a result of the foregoing indications, we believe that one of the most unfortunate aspects of the President's National Energy Plan and the National Energy Act is a proposed change in national policy away from discouraging the allocation of scarce liquid petroleum products for SNG plants to a policy that not only would allocate such products to existing SNG plants, but also would encourage construction of new SNG plants. The stated purpose of this dramatic shift in policy is found on page 57 of the President's National Energy Plan where it is stated: ". . . the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months."

We respectfully suggest that those that reached that conclusion have been misled concerning the contribution of SNG to solving the national natural gas supply problem, including this past winter's shortage. We will demonstrate from publicly available information, that many, if not all, of the existing SNG plants were on systems where either boiler fuel loads, including generation of electricity, were served during the winter or natural gas purchases were cut back while SNG production was continued.

In addition, as FEA's SNG policy has long recognized, SNG derived from liquid hydrocarbons, such as propane, butane and naphtha, is neither a solution, nor a mitigation, of the increasing natural gas shortages facing consumers, including the industrial feedstock and process users who have no alternatives.

We further point out that the inefficient, wasteful conversion of liquid hydrocarbons to SNG [2] simply is inconsistent with other features of the national energy plan that promote efficient use of energy resources,[3] increased reliance on abundant sources of energy such as coal, and preserve scarce energy resources for use only where there are no alternatives. How a policy that is bottomed on the assumption that natural gas and liquid petroleum production has peaked and is tapering off [4] can at the same time encourage a new increased use of already scarce liquid hydrocarbons in new and existing SNG plants escapes us. We can only hope that after the Administration and the Congress examine the SNG issue the promotion of wasteful energy reducing liquid-based SNG plants will come to an abrupt end. Most importantly, before any change in SNG policy is made, a thorough study should be conducted of the precise contribution of SNG to satisfy high priority needs. Also, a thorough study of the inefficiency and waste of SNG plants needs to be made.

THE FACTS AS TO SNG

Background

As of October, 1973, forty-nine liquid-based SNG plants were planned, designed to use almost 3,000,000 barrels per day of liquid hydrocarbon feedstocks, including

[1] President Carter's National Energy Plan, issued April 29, 1977.
[2] FEA Policy Statement regarding SNG plants, 39 F.R. 27911 (August 2, 1974).
[3] National Energy Plan, page ix.
[4] *Id.*, page vii.

crude oil, naphtha and natural gas liquids. (See Attachment A.) As of January, 1977, 13 SNG plants were operational. (See Attachment B.) Twelve of these SNG plants are located in the continental United States and are currently available to supplement natural gas supplies as follows:

	Design SNG output (MMcf/d)	Design feedstock[5] volume (MB/D)	Design operation (days)	Current maximum output (Bcf/Y)
New England:				
Algonquin SNG, Inc.	120.0	26 N[6]	151	18.1
Boston Gas Co.	40.0	10 P[7]	180	7.2
Middle Atlantic:				
Ashland Oil, Inc.	60.0	11 N	350	21.0
Brooklyn Union Gas Co.	60.0	13.7 N	180	10.8
PSE&G (Linden)	125.0	25 N	350	43.8
PSE&G (Harrison)	20.0	4 N	350	7.0
South Atlantic:				
Baltimore Gas & Electric Co.	60.0	12 N	180	10.8
Commonwealth Natural Gas Corp.	29.5	6.45 NGL[8]	154	4.5
East North Central:				
Columbia LNG, Inc.	250.0	70 NGL	350	87.5
Consumers Power Co.	200.0	50 NGL	350	70.0
NI-Gas	166.0	32 NGL, 16 N	350	58.1
Peoples Gas Light & Coke Co.	160.0	33 N	350	56.0
Total				394.8

[5] In addition to feedstock volumes, at least 5 SNG plants are seeking a total of 2,599,620 barrels per year of propane for "Btu enrichment." (41 F.R. 54217, Dec. 13, 1976).
[6] Naphtha.
[7] Propane.
[8] Natural gas liquids.

Source: FEA, AGA.

If each of these existing plants were authorized or otherwise able to operate at full capacity for a full year (350 days per year), the maximum SNG output would be 451.7 billion cubic feet (Bcf) per year and the total feedstock demand for liquid hydrocarbons would be 309 thousand barrels per day (MB/D) (141 MB/D of naphtha and 168 MB/D of NGL).

To contribute 1 trillion cubic feet (Tcf) of gas annually by 1980, current SNG output would have to be almost tripled and current usage of liquid hydrocarbons would have to increase from 309 MB/D to from 600–850 MB/D of liquid hydrocarbons, depending upon the feedstock to be utilized.

Current FEA policy is sound, the facts have not changed

As FEA's *Statement of Policy*[9] has recognized, there are at least 13 plants operating or under construction—representing a new and inferior end use in excess of 300,000 barrels per day of liquid hydrocarbons.

There is no question, even in the minds of those seeking to operate SNG plants, that there are insufficient supplies of these products—from either foreign or domestic sources.[10] Likewise, the President's National Energy Plan forecasts substantial shortages of petroleum products.[11] The conclusion that we reach, therefore, is: to supply these SNG plants, liquid hydrocarbons must be diverted from existing high priority users. In addition, we cannot help but be concerned about those SNG plants permitted to run on imported products, and the threat they pose to domestic supplies if those imports should prove unreliable.

[9] See 39 F.R. 27911, August 2, 1974.
[10] See, e.g., "Current Availability of U.S. Supplies of Light Hydrocarbon SNG Feedstocks," prepared for Consumers Power Company, May, 1974, which concludes: "There presently is [sic] insufficient supplies of uncommitted domestic light hydrocarbon feedstocks for Consumers Power Company's Marysville SNG plant." p. 8.
And see, e.g., letter dated August 20, 1974 from R. D. Morel, Vice President-Administrator, Algonguin Gas Transmission Company to Executive Secretariat, FEA, where it is stated:
"Algonquin is unable to purchase any domestic naphtha, other than quantities under the Exxon contract, and foreign imports are available only on a spot basis. Operation of the plant on its projected schedule would not be feasible on the basis of such imports. Such *foreign* shipments are not available on a long-term contract basis and hence are not reliable." (Emphasis added.)
[11] National Energy Plan, page vii.

Others will speak their concern, but the impact of such a diversion on the petrochemical industry and the industries and consumers dependent upon our products could be particularly severe. Petrochemical products have become increasingly important to the nation's business and welfare.[12] For example, as the President's Committee on Food has indicated,[13] American farm producers have increasingly and very effectively utilized herbicides, insecticides and fungicides to protect and increase farm output. It is estimated by some USDA scientists that the use of pesticides alone has accounted for at least 20 percent in farm output since 1940. Other agricultural experts indicate that use of herbicides has reduced cultivation by 50 percent to 160 million acres of agricultural land in the United States, which in terms of fuel uses for cultivation means a savings from 94 to 170 million gallons of fuel depending upon the type (gasoline, diesel, or LPG). The Senate Committee on Agriculture and Forestry has concluded that "regarding the future availability of these essential farm chemicals, especially during the immediate future, . . . critical shortages of some of them could very well develop."

Other products and other industries are similarly affected by shortages.[14] The point is, existing petrochemical plant investment exceeds $20 billion and current petrochemical production exceeds $25 billion annually. The diversion of liquid hydrocarbons to SNG plants exposes this investment and needed production capacity to an additional risk of curtailment.

Allocation programs create not one drop of additional supplies; they can only indicate in a time of shortage how supplies should be divided among competing end uses. Faced with requests from SNG plants to divide existing supplies of liquid hydrocarbons into an additional portion in order to supplement shortages in the natural gas market, FEA determined that the public interest required all such requests to be handled on a case by case basis, prior to the allocation on a priority basis of any SNG feedstocks. Opportunity would be afforded interested parties to challenge or support such requests on an individual basis and according to specific criteria. A special Rule was established to provide a procedural framework.

Further, FEA's Statement of Policy clearly indicates that each petitioner would carry a heavy burden of establishing in the public interest the necessity for diverting scarce, premium fuels to a new and wasteful use. FEA concluded:

"The manufacture of SNG from petroleum is, in most instances, an inefficient use of resource, . . ."; and

"Accordingly, FEA will implement a policy which, in general, discourages allocation of scarce petroleum resources to manufacturers of SNG."

Further, FEA stated that:

". . . the special rule issued today will operate to eliminate SNG manufacture from liquid hydrocarbon feedstocks as a supplemental supply alternative for the majority of these companies.

* * * * * * *

"It is FEA's policy to encourage further commitment by these companies to alternative means of supplementing gas supplies which do not result in the serious drawbacks associated with SNG manufacture from liquid petroleum."

We believe the policies and procedures toward SNG plants embodied in FEA's Statement of Policy are correct and make good sense. We believe they deserve continued wholehearted and effective implementation, both in spirit and in letter. To do otherwise, would prejudice aggrieved parties, contradict existing energy policies and discredit the agency.

Both in the long and short term, it makes little sense and worse policy to allow, except under strigent limitations, the conversion of one clean fuel or petrochemical feedstock into a clean fuel in another form at high cost to the

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[12] The automobile industry depends upon paints, plastics and synthetic rubbers; the textile industry upon synthetic fibers; the agriculture industry upon fertilizers and pesticides; and the pharmaceutical industry upon a variety of complex organic chemicals and solvents.

[13] See Senate Report No. 93–1138, September 5, 1974, on Importance on Farm Inputs.

[14] A clear indication of the importance of petrochemicals to other industries is the Committee Print, "Materials Shortages—Industry Perceptions of Shortages," August 1974, prepared by the Permanent Subcommittee on Investigations of the Committee on Government Operations, U.S. Senate, which tabulates the responses of the 500 largest U.S. companies and concludes: "By far the most universal shortage was in petrochemicals. . . ." p. 23.

consumer and at the loss of the energy used in converting a liquid into a gas. The American Gas Association (AGA), as late as January, 1972, was apparently advocating this same position.[15]

It seems clear that the concept of petroleum-based SNG is and has been badly out of step with all of the tenets of the President's national energy policy except the claims on page 57 of the National Energy Plan. At a time when the President is calling for a 10 million barrel a day reduction in oil imports,[16] it seems strangely inconsistent that a policy would be proposed that would promote a new demand for petroleum with a potential in excess of a million barrels per day. At a time when inflation, shortages and energy wastage have become serious public concerns, it seems strange that the President's energy policy would promote SNG manufacture which wastes from 10-15 percent of its feedstock; which results in a synthetic product costing $3.00-{.00 per Mcf; and which could divert almost 20 percent of the U.S. supply of propane and butane.

At a time when U.S. policy is to eliminate oil-fired electric generators by 1980,[17] it seems strange that the President's energy policy would promote SNG manufacture for use under electric utility boilers, that have alternate fuel capability, especially where high priority natural gas customers are required to subsidize this inferior use of energy.

At a time when propane and other liquid hydrocarbons are restricted in their use for peak shaving so that interruptible end users and those end users with alternate fuel capability are not served, it seems strange that the President would propose a plan to permit SNG manufacture so that the same interruptible end users continue to be served.[18]

At a time when FEA is restricting traditional users of covered product to base period levels[19] and permitting adjustments for "changed circumstances" only where a petitioner can show "serious hardship or gross inequity,"[20] it seems strange that the Administration would permit a new and wasteful use of petroleum products so that expansion in low priority markets can be served at the same time existing customers in another market are being restricted to historical levels.

Since FEA addresses short term natural gas curtailments by allocating petroleum products directly to end users curtailed on natural gas (§ 211.12(h)), it seems strange that the Administration would propose the diversion of these same pretroleum products to inefficient SNG manufacture where it is not needed to meet curtailments of high priority customers.

At a time when vast amounts of capital and equipment are required to achieve increased exploration and development of new energy resources, it seems strange that it would be suggested that the national energy policy should promote the diversion of these capital and equipment resources to SNG manufacture an unnecessary and wasteful purpose. One alternative, in particular, requires mention. According to FEA, a potential 30 to 60 billion barrels of oil, and 300 to 600 trillion cubic feet of gas, could be produced through enhanced recovery methods, thanks to technologies that are just now emerging.[21]

Lastly, government policy regarding SNG manufacture has been consistent and clear for years. Under the Oil Import Program administered by the Office of Emergency Preparedness and the Oil Policy Committee, it should have been clear that SNG was not a viable means of meeting foreseeable natural gas shortages.[22] The position of the Federal Power Commission has been equally

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[15] At SNG symposium I, held in Chicago in March 1973, and sponsored by the Institute of Gas Technology, an official of the U.S. Department of Treasury summarized the comments of the AGA which had been filed concerning the importation of naphtha under the Oil Import Program for SNG manufacture:

"Some, such as the American Gas Association, suggested that the amounts imported should be limited under the OIP so as not to flood the market. This argument was particularly advanced in regard to naphtha-SNG because it is an inefficient energy source as it involves converting one clean energy source into another with a resultant loss of energy and added cost." (Papers, SNG symposium I, March 12-16, 1973 · p. 451).

[16] Address of the President to the Joint Session of Congress, October 8, 1974 (Release of the Office of the White House Press Secretary, p. 4). National Energy Plan, page xiii.

[17] *Ibid.*

[18] See, e.g., 10 C.F.R. § 211.83(c)(2)(v).

[19] See §§ 211.86(g) and 211.10(g)(9), for example.

[20] See 39 F.R. 36854, October 15, 1974.

[21] See FEA Release FEA-F-132, E-74-497, November 26, 1974.

[22] See, e.g., Decision of Oil Import Appeals Board, November 30, 1973, in *Algonquin Gas Transmission Company*, OIAB No. 33-73.

clear and consistent.[23] Nevertheless, those would construct and operate SNG plants have not heeded these policies and now seek commitments and assistance from both the FEA, the Administration and lawyers which they could not obtain from earlier energy policy makers. It seems strange that a new policy would emerge and reward such lack of foresight and disregard of declines in liquid hydrocarbons.

The dubious value of high-priced SNG to residentials

If SNG were truly as vital as a source of gas as page 57 of the National Energy Plan assumes, why is it that the bulk of the SNG produced is not sold at its cost? Instead, SNG often is sold to electric utilities for use in the generation of electricity at dollars below its cost.[24] That means residential consumers are absorbing the high cost of SNG while gaining no measurable benefit. If SNG were as necessary as some suggest, it should be able to stand the test of being sold at its cost of production rather than having its cost[25] hidden by lower-cost flowing gas.

Before allocations of scarce liquid petroleum feedstocks are made to existing or prospective SNG plants, the SNG company should be required to establish—

(*a*) That SNG is in fact needed to protect high priority users; or

(*b*) That the entire output of its plant is contracted for at the incremental cost of producing the SNG.

Full SNG production, however, was not needed this winter to keep homes warm. Instead, expensive SNG was used to supply low priority uses even during the severest part of the gas shortage this past winter. Consequently, it is difficult to conclude that SNG provided the margin of gas supply that kept homes warm this winter. We note also that in no case was SNG sold for electric generation priced at the cost of SNG (i.e., incremental pricing). Therefore, not only did the residential user not need the SNG, but SNG is so costly that he was forced to subsidize it anyway.

Need for liquid-based SNG to meet residential requirements

In the President's National Energy Plan (page 57), it is asserted that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Such a conclusion will not stand analysis. However, we make clear that regardless of the waste and inefficiency of using liquid hydrocarbons in SNG plants, if it could be established that SNG was in fact needed to keep residentials from being curtailed, there might be some basis for reassessment of present FEA policy towards SNG plants in those particular instances.

At a minmum, before any extension of existing allocations or new allocations of natural gas liquids or naphtha are made, the owner of the SNG plant should be required, as a precondition, to establish the necessity or justification of an allocation. These standards should require that an allocation is granted only if—

The allocation is exclusively as feedstock in the SNG plant;

the allocation is only used to produce SNG when necessary to meet the historic requirements of customers classified in FPC priorities 1 through 3 who do not have the *technical* capability of using alternate fuels;

the utility is not making interruptible or boiler fuel sales while it is operating the SNG plant;

the allocation is not used to foster growth;

the allocation is granted only if the SNG will be incrementally priced to the ultimate class of end user;

it is established that alternative supplies of gas have been exhausted; and the feedstock supplies are "surplus" to the requirements of existing high priority users.

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[23] See PEG Testimony in May. As recently as September 16, 1974, an FPC Administrative Law Judge denied a proposal by Natural Gas Pipeline Company of America to purchase SNG at from $3.02 to $4.31 per MMBtu. It was found that *inter alia* the high cost of the gas precluded its resale at a price that would recover its cost, that the manufacture was an expensive and inefficient use of resources and imposed costs on classes of consumers receiving no benefits.

[24] For Conumers Power Company, its SNG costs at least $3.25–3.50 to produce, yet it sold it to itself for electric generation for a maximum price this winter of $1.75 and to Detroit Edison for $1.98. Source: Consumers Power Company Form 423 and Detroit Edison Form 423 on file at the FPC.

[25] $4.00 SNG is the equivalent of $23.50 oil.

Appendix X

Federal Power Commission—Bureau of Natural Gas

Direct Testimony of Cristobal Hernandez

Senator Howard Metzenbaum

v

Columbia Gas Transmission Corporation

[Docket No. RP77-35]

Q. Please state your name and by whom you are employed.

A. My name is Cristobal Hernandez. I am employed by the Federal Power Commission as a Public Utilities Specialist (Gas) in the Pipeline Certificate and Curtailment Division of the Bureau of Natural Gas.

Q. Briefly describe your education and experience before joining the Federal Power Commission.

A. I graduated from the University of Texas in July, 1962, with a Bachelor of Science degree in petroleum engineering and began work with the FPC the following September.

Q. What has been the nature of your duties since you became employed by the Federal Power Commission?

A. I have been responsible for the investigation and evaluation of pipeline certificate applications including many of the major pipeline expansion projects. This investigation covers analyses of all major aspects of a project and, among other things, includes market evaluation, operational studies, both of past performance and proposed utilization of facilities, and economic feasibility studies. I presented testimony and exhibits in the Tennessee-Algonquin case, Docket No. CP65-340. et al., relating to the economic feasibility of Algonquin's proposal. I have also testified in the curtailment cases of Transcontinental Gas Pipe Line Corporation (Docket No. RP72-89) and Columbia Gas Transmission Corporation (Docket No. RP72-89). I also testified in a special relief proceeding concerning the City of Winfield, Kansas. I have also assisted in the preparation of staff exhibits and served as technical representative of the Bureau of Natural Gas in various other formal proceedings. My current duties include analyses of curtailment and certificate filings which are likely to result in formal hearings, with specific responsibility for the Transco and Columbia curtailment and "omnibus" proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to set forth my conclusions relating to the allegations contained in Senator Metzenbaum's complaint of February 11, 1977, against Columbia as required by the Commission's order issued March 31, 1977, in this proceeding. Specifically, I evaluated: (1) the circumstances surrounding Columbia's decision to lift curtailment effective September 27, 1976, through the October, 1976, billing month; (2) the effect this decision had on Columbia's storage balances commencing with the 1976-77 winter season; and (3) the necessity of Columbia having to purchase emergency supplies of gas for its customers in order to restore storage balances.

As part of my evaluation, I utilized Columbia's reply to staff's data request dated April 15, 1977. Additionally, I made a two week field trip to Columbia's office in Charleston, West Virginia and to company offices of other Columbia affiliates to acquaint myself with the Columbia Gas System, Inc. methods of operation and decision making. I also obtained additional operating data to further evaluate Columbia's operations during the past summer season.

Q. What were the circumstances that, in your view, prompted Columbia to cancel its curtailment effective September 27 for the remainder of the summer season?

A. Columbia has three options in managing its flowing gas supply. It can deliver all the supply to its customers, it can store part of it, or it can cut back on its gas supply sources.

Columbia allocates its available gas supply to its customers on a seasonal basis. These customers are allocated specified authorized volumes for the summer season (April-October) and for the winter season (November-March).

Columbia's customers as a whole were not taking their authorized volumes for the summer season. By the end of September, 9 Bcf of authorized volumes under

Columbia's curtailment plan had not been taken by the customers. At the same time, Columbia's storage balances (volumes in storage less native gas) were above scheduled volumes by approximately 3.4 Bcf.

Looking at October, Columbia's authorized volumes for its customers, and other system demands such as fuel requirements, totaled 82.8 Bcf.

Its storage balance as of the end of September was 583.4 Bcf, which meant only 6.9 Bcf were required during the month of October to reach Columbia's scheduled storage inventory of 590.3 Bcf. The total of these authorized volumes and storage requirements for October is 89.7 Bcf. Columbia's scheduled gas supplies for October were 95.6 Bcf. Thus, Columbia had the option of continuing curtailment and having to cut back on available supplies totaling 5.9 Bcf for the month of October, or lifting curtailment and making these volumes available to its customers.

Q. Is it your conclusion then that Columbia's decision to cancel curtailment effective September 27 was a prudent decision?

A. Yes. Based on the circumstances then existing, Columbia's decision to lift curtailment was, in my judgment, reasonable.

Q. What happened during October, 1976?

A. Columbia was injecting gas into storage on a consistent basis through October 16. After this date, however, the weather turned cold and Columbia was required to begin withdrawing substantial volumes of gas from storage in order to meet the demands on its system. Withdrawals were such that by November 1, 1976, Columbia had an actual storage balance of 565.3 Bcf. This is 25.0 Bcf below the scheduled quantity of 590.3 Bcf.

Q. Did Columbia take any action to limit storage withdrawals after October 16?

A. Not to my knowledge.

Q. Do you believe Columbia should have taken action at the time it began experiencing large withdrawals from storage after October 16?

A. Yes. The protection of storage balances is of paramount importance. Columbia's tariff provides as follows:

14.3 Storage protection and gas supply deficiency curtailment

(a) If, in Seller's sole judgment, Seller's gas supply is not adequate to deliver the Maximum Monthly Volumes to each Buyer, and to inject the necessary volumes of gas into Seller's underground storage fields, then Seller shall order curtailment of deliveries to Buyers under Seller's firm Rate Schedules, except Rate Schedule SGS, by giving notice to each Buyer of the Ordered Curtailment applicable to each Buyer's Maximum Monthly Volume and the Authorized Monthly Volume that Buyer is entitled to take for such month or portion thereof. Such notice will be given as much in advance as possible. Provided, further, that on any given day, if, in Seller's sole judgment, Seller's gas supply is not adequate to deliver the Total Daily Entitlements to each Buyer, and to inject the necessary volumes of gas into Seller's underground storage fields, Seller shall not be obligated to deliver to Buyer its Total Daily Entitlement.

Columbia itself recognized this in its letter to the General Counsel of the Commission by letter dated November 17, 1976, wherein it states:

"If we assume normal weather from this date forward, it would appear that the storage deficiency at November 1 of 24.4 bcf will persist. Consequently, on any given day after February 14, 1977, we estimate that the 24.4 Bcf deficiency will result in a reduction of between 400–500 million cubic feet of deliverability. Such reduction of deliverability greatly reduces the safety factor in Columbia Transmission's storage. Accordingly, we believe that it is prudent to attempt to reduce the indicated deficiency in storage and the resulting storage deliverability."

Further, affirmative action to protect storage is required by Order No. 431 (45 FPC 570) under which Columbia's curtailment plan was filed. Furthermore, Columbia itself took action this past January pursuant to Section 14.6 of its tariff in order to forestall irreparable injury to life and property. This action required that Columbia's customer's deliver only to Priority 1 and other essential human needs customers. This action was required to protect storage, which is required to provide protection to high priority customers. Columbia's storage provides over half of its peak day supply. Thus, the safety of residential consumers and other essential human needs customers depends on the protection of Columbia's storage.

Finally, Columbia's entire summer curtailment plan is greatly influenced by its storage requirements. The authorized summer volumes of Columbia's customers are determined by the volumes of gas available *over and above* those needed by Columbia for storage injection. In other words, storage has the first call on Columbia's flowing gas supply during the injection season and the remaining supply is used for purposes of determining the authorized summer entitlements of Columbia's customers, including its own affiliates.

Q. What type of action should Columbia have taken in your judgment?

A. I believe Columbia should have acted immediately to protect storage by prohibiting low priority sales by its customers commencing on October 17, 1976. Such action would have reduced Columbia's storage deficiency as of November 1 by approximately 7.5 Bcf. By low priority sales I refer to (1) sales to industrial customers in Priority 3 of Columbia's curtailment plan, and (2) large commercial and industrial users in Priority 2 having installed alternate fuel capability. Priority 3 sales are boiler fuel sales in excess of 300 Mcf per day.

Q. How did you determine the amount of 7.5 Bcf?

A. I determined this amount from responses to the staff's data request. These responses revealed that during the period October 17 through October 31, 1976, approximately 7.5 Bcf was sold by Columbia's customers for low priority uses. This volume represents the low priority sales made by distributor customers who account for 93 percent of Columbia's summer market requirements.

Q. You earlier testified that Columbia's storage deficiency on November 1 was approximately 25.0 Bcf and 7.5 Bcf is accounted for by low priority sales. What accounts for the remaining approximately 17.5 Bcf of storage deficiency as of November 1?

A. This volume was required to meet high priority market demands.

Q. Could Columbia have prevented low priority sales by its customers commencing October 17?

A. In my judgment, yes.

Q. How would this be accomplished?

A. The most direct way was for Columbia to notify its customers that effective October 17 through the October billing month, they were not to make sales to commercial and industrial customers which had installed alternate fuel capability or for large boiler fuel use. This method would have prevented economic dislocations and still protected storage to the extent possible.

Q. What would have been the impact of this curtailment plan?

A. Based on the aforementioned customer replies, Columbia would not have delivered approximately 7.5 Bcf to its distributor customers. These volumes would then have remained in storage and partially offset the 25.0 Bcf deficit.

Q. Is such action within the purview of Columbia's effective curtailment plan?

A. Yes. As I have previously testified, Columbia's plan specifically requires Columbia to take affirmative action to protect storage. Stated Commission policy also requires the curtailment plans of regulated pipeline companies to provide for this protection.

Q. Please state your conclusions.

A. Had Columbia taken the necessary action to protect storage, it would have had additional gas volumes of approximately 7.5 Bcf in storage on November 1. This volume would have been available to help meet Columbia's winter season requirements and would have reduced, by an equivalent amount, its need for higher priced emergency supplies. I therefore conclude that Columbia's purchase of emergency gas supplies was imprudent to the extent of 7.5 Bcf.

Q. Does this conclude your direct testimony?

A. Yes.

SALES TO PRIORITY 3 CUSTOMERS AND TO PRIORITY 2 CUSTOMERS WITH INSTALLED ALTERNATE FUEL CAPABILITY DURING THE PERIOD OCT. 17-31, 1976

[In millions of cubic feet]

Customer	Priority 3	Priority 2	Total
Baltimore	586,943	678,055	1,264,998
Cincinnati	273,881	719,568	993,449
Union L.H. & P.	39,641	41,975	81,616
CNG Transmission	390,468	115,136	505,604
CDC companies	1,354,727	2,752,761	4,107,488
Dayton	48,863	43,741	92,604
UGI			18,450
Washington Gas	19,395	392,418	411,813
W. Ohio	3,642	7,228	10,870
Total	2,717,560	4,750,882	7,486,892

These standards would go a long way toward assuring that scarce and valuable liquid hydrocarbons are not made even more scarce by expanded use in SNG plants for SNG that is not needed to meet the high priority needs of the country.

Our factual analysis of the 13 existing SNG plants and their contribution to keeping residential customers warm this winter follows:

BALTIMORE GAS & ELECTRIC CO.

On page 57 of the National Energy Plan it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information indicates that this statement does not appear to apply to Baltimore Gas & Electric Co. (BG&E) because their SNG plant, originally scheduled for start-up in December 1976 did not make its initial start-up until February 7, 1977.[26] That attempt was abortive and adjustments apparently are required before production can commence.[27] As a result, it cannot be said that BG&E's SNG plant provided the margin of gas supply that kept residentials from curtailment this winter.

Further, BG&E apparently had sufficient gas supply to use 18,000 Mcf for electric generation in January 1977.[28] Although that is not a large volume of gas, it does illustrate that BG&E had more than ample supplies to meet the winter needs of residentials. Also, in BG&E Form 100 filed with the SEC for the 1st quarter of 1977, it was indicated that "some large commercial and industrial firm customers [were] temporarily cut off for eleven days . . . to provide sufficient quantities of gas for residential and small commercial customers. . . ." [29] Accordingly, SNG, even if the plant had been operational, would not have been needed to prevent the shutting off of residentials.

A general summary of BG&E's SNG operation follows:

SNG production

In 1976, the plant was not operational. Initial start-up was attempted in February 1977 but problems arose and production did not commence this winter.[30] Production is proposed to reach 60,000 Mcf per day and operations are proposed for 180 days per year.

Assuming production of 60,000 Mcf of SNG per day, this would constitute 10 percent of BG&E's total system gas supply.[31] Unless BG&E becomes dependent on 10 percent of its supply to service its residential customers, it is unlikely that SNG will be needed to prevent residential curtailment in the future. Further, BG&E recognizes that supplemental gas will not solve the gas supply shortage.[32]

Feedstocks

BG&E's SNG plant is designed to use naphtha as a feedstock at the rate of 12,000 bbls per day. Presently BG&E is operating under a temporary allocation allowing it to use 66,600 barrels from inventory and to purchase and use 425,000 barrels for the second and third quarters of 1977 for start-up and testing.[33]

No evidence that residentials and small commercials were curtailed

We are aware of no evidence indicating that residentials or small commercials were curtailed this winter. Therefore, it is patently clear that SNG did not provide the margin of safety needed to service residentials this winter.

BOSTON GAS CO.

On page 57 of the Administration statement of energy policy, "The National Energy Plan," it was stated that residential service was maintained through the winter in several areas of the country because of the contribution of the thirteen operating SNG plants. However, a review of public information as to Boston Gas Co. (Boston Gas) indicates that its SNG did not make a critical difference to residential customers this winter. Instead, statements by Boston Gas suggest that

[26] See FEA order of April 7, 1977, involving BG&E request for waiver attached as Baltimore Gas & Electric Exhibit No. 1.
[27] *Id.*
[28] See Form No. 423 for January 1977 attached as Baltimore Gas & Electric Exhibit No. 2.
[29] BG&E Form 10-Q, BG&E Exhibit No. 3.
[30] Footnote 26, *supra*.
[31] BG&E Annual Report 1976, page 8 attached as Exhibit No. 4.
[32] *Id.*
[33] Baltimore Gas & Electric Exhibit No. 1.

it met all the requirements of its firm customers. If that is the case, it is hard to see how SNG provided a margin of safety.

SNG production

The Boston Gas plant in Everett, Massachusetts is one example where a plant appears not to have made a critical difference this winter. The plant has a design capacity of 40,000 Mcf/day,[34] equal to the propane-air peak shaving capacity which Boston Gas had before building the plant.[35]

To produce this volume requires 1,484,047 barrels of propane.[36] Unlike an SNG plant, however—which involves a catalytic reformation of the molecular structure of the feedstock a propane-air injection plant can be started up as the need arises and thereafter shut down when the need has passed. Further, because a propane-air plant involves merely the injection of propane into the natural gas stream, the operating efficiency of the plant is very high. This compares with the Btu losses associated with the operation of an SNG plant and the fact that because an SNG plant involves a catalytic process, it cannot be started up and shut down in rapidly repeated sequence to meet temporary peak demands. Thus, Boston Gas already had peak-shaving facilities capable of more efficiently producing the same volumes of supplemental supplies of gas even before construction of the SNG plant. In 1976, Boston Gas produced 7.2 Bcf of SNG or 11 percent of its total firm sendout.[37] Since the SNG plant is only operated in the winter, the percentage of SNG to winter sendout is about 20 percent.

Sales of SNG

Boston Gas claims to make no sales of gas to other than firm customers which would be classified in FPC priorities one and two when its SNG plant is operating.[38] However, it clearly admits that it makes sales to interruptible customers when its SNG plant is not running.[39] This gas need not be used for low-priority uses merely because it is excess; such gas could clearly be marshalled to offset any necessity for SNG production. This is particularly so when the fact of these interruptible sales is combined with the availability of propane air facilities for use on those days when the supplies of gas from other sources is insufficient.

No evidence that SNG saved residentials from curtailment

SEC filings reflect the adequacy of Boston Gas supply even without SNG as far as being able to serve its residenital users even without SNG. A filing reflecting the company's operatons during the first quarter of 1977 noted that Boston Gas' supply had been adequate to meet its firm customers requirements.[40] Further, Boston Gas' 10-K for 1976 noted that Boston Gas' fully expected to meet the gas requirements of its firm customers, noting merely that due to priority allocation of natural gas, " deliveries to low priority customers" might be affected.[41] We are aware of no public information indicating that SNG provided the margin that prevented curtailment of residentials.

Price of SNG

Comparison of the fact that Boston Gas is making interruptible sales of natural gas, one would assume at low prices, with the fact that for these supplemental supplies which Boston Gas is providing for its customers, it is paying an average of $3.00/Mcf.[42] That SNG must significantly up the average price of gas is reflected by the fact that the SNG Boston Gas purchases from Algonquin costs $4.923/Mcf.[43]

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[34] Eastern Gas and Fuel Associates' Form 10-K (1976) filed with the Securities and Exchange Commission on March 24, 1977, at 7 [Boston Gas Exhibit No. 1].

[35] Letter of July 12, 1976 from Kenneth I. Schaner and Lester S. Hyman to the Federal Energy Administration, re: Application of Boston Gas Co. for Allocation of Synthetic Natural Gas Feedstock [hereinafter "Letter"] at 4 [Boston Gas Exhibit No. 2].

[36] *Id.* at 1.

[37] Eastern Gas and Fuel Associates' Form 10-K, *supra*, at 7 [Boston Gas Exhibit No. 1].

[38] Letter of 7/12/76, *supra*, at 3 [Boston Gas Exhibit No. 2].

[39] Application of Boston Gas Company, dated July 12, 1976, for Allocation of Synthetic Natural Gas Feedstock [hereinafter "Application"] at 17-18 and 20 [Boston Gas Exhibit No. 3].

[40] Eastern Gas and Fuel Associates' Form 10-Q [quarter ending March 31, 1977] filed with the Securities and Exchange Commission on April 27, 1977, at 10 [Boston Gas Exhibit No. 4].

[41] Eastern Gas and Fuel Associates' Form 10-K, *supra* [Boston Gas Exhibit No. 1].

[42] *Id.* at 7.

[43] Algonquin Gas Transmission Company's Form 2 (1976), filed with the Federal Power Commission on April 4, 1977, at 521 [Boston Gas Exhibit No. 5].

Finally, consider the fact that Boston Gas stated in its Annual Report to the SEC that it expected to receive 7.150 Bcf in gas supply from its SNG and LNG facilities.[44] In light of the fact that the output of the SNG plant is 7.2 Bcf over the 180-day period during which it operates, it would appear that Boson Gas has unused LNG capacity which it could further use to obviate the need for SNG production.

In short, it would appear that as to Boston Gas, the SNG plant did not perform the role this winter attributed to it, e.g., averting the termination of service to residential users. Rather, it appears to have been a source of high-cost, supplemental supplies of natural gas which could have been forgone in light of the other facilities and potential arrangements available to Boston Gas.

COMMONWEALTH NATURAL GAS CORP.

On page 57 of the National Energy Plan it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information as to Commonwealth Natural Gas Corp. (Commonwealth) reveals that it cannot categorically be stated whether or not its SNG, which constitutes only 16 percent of its supply,[45] prevented curtailment of residential users this past winter.

We do know from Commonwealth's statements[46] that supplemental supplies may have been needed to serve priorities 1–3; however, public information does not show whether such supplies were needed to serve priority 1—residential users.

In addition, the need for SNG for residentials is clouded by the fact that at a time when Commonwealth's suppliers were curtailing it, Commonwealth increased its sales from 47.5 Bcf in 1975 to 55.5 Bcf in 1976.[47] This increase exceeds its maximum yearly SNG production of 4.53 Bcf.[48] Further, last summer Commonwealth told the FEA that SNG enabled it to serve priority 4–9 customers.[49] In addition, Commonwealth has indicated that the new state curtailment plan should only affect interruptibles[50] so that it appears that residentials are not close to being curtailed. Therefore, even after the cold winter, the only way it can be claimed that SNG kept residentials warm is that Commonwealth increased its sales and continued to serve low priority customers when it should have saved the gas for high priority users.

SNG production

Commonwealth's SNG plant is designed to produce 30,000 Mcf on a maximum day. This constitutes about 16 percent of the company's gas supply on a peak day.[51] However, Commonwealth did not operate at full capacity in 1976 and, at the present time, Commonwealth operates its SNG plant for only 151 days (November–March), out of the year. For 1976, Commonwealth had to curtail some interruptibles but no firm customers.[52] Similarly, Commonwealth has noted that a state curtailment plan has been imposed but that it would effect only interruptible sales in future years.[53] SNG may help deliverability and it helps growth,[54] but there is no evidence it is the margin required to keep residentials warm.

Feedstocks

Commonwealth's SNG plant is designed to use 6,450 barrels a day of propane or butane. Presently, Commonwealth has a temporary allocation of butane of 540,962 barrels for the 1st quarter of 1977.

Adherence to special rule No. 1

Although Special Rule No. 1 indicates SNG plants should not be operated when interruptibles are being served, Commonwealth serves Suffolk when its SNG plant

[44] Eastern Gas and Fuel Associates, Form 10–Q, *supra*, at 7 [Boston Gas Exhibit No. 4].
[45] Commonwealth 1976 Annual Report, p. 2 attached as Commonwealth Exhibit No. 1.
[46] Commonwealth Application for Stay filed with FEA on January 13, 1977.
[47] Footnote 45, *supra*.
[48] 30,000 Mcf/d times 151 days of production at 4.53 Bcf.
[49] Letter from Commonwealth to FEA attached as Exhibit No. 2.
[50] Footnote 1, *supra*, p. 4.
[51] Commonwealth Natural Gas Corp. Annual Report 1976, attached as Commonwealth Exhibit No. 1.
[52] *Id.*
[53] *Id.*
[54] *Id.*

is operating. Further, although Commonwealth may have designed its contracts so it has only one interruptible customer, many of its customers have interruptible loads. In 1975–76 for example, Commonwealth's customers sold 850,000 Mcf on an interruptible basis.[55] We have no information from which it can be determined whether interruptibles were being sold gas this winter while the SNG plant was operating.

Boiler fuel use of gas

Although we have not found information as to boiler fuel sales this winter, Commonwealth in a letter to FEA indicated that SNG made sales of gas to FPC categories 4–9 possible.[56] This is a pretty good indication that over the course of a year, many boiler fuel sales are made because of SNG. Also, one of Commonwealth's customers, VEPCO, used gas to generate electricity in 1976.[57] As long as SNG is the gas supply for low priority uses, it is difficult to conclude that it is the margin of gas needed to keep residentials warm.

No evidence that residentials and small commercials were curtailed

Although the winter was severe in Virginia, Commonwealth's major distributors reported that, in 1976, they experienced some interruptible curtailment and no firm curtailment.[58]

Commonwealth, in filings with the FEA this winter,[59] indicated a need for gas to serve its priorities 1–3 and indicated that human needs customers might be curtailed.

As a further indication of Commonwealth's gas supply picture, at a time when it was being "curtailed" by its suppliers, it increased its sales from 47.5 Bcf in 1975 to 55.5 Bcf in 1967.[60] That is more than the production of SNG from its plant.[61] Therefore, SNG, rather than providing the margin of gas supply for residentials, may instead be the foundation for growth.

If protection of residentials is the goal, Commonwealth can attain that objective by limiting low priority sales in the summer and limiting growth rather than developing an increased reliance on high priced SNG.

BROOKLYN UNION GAS COMPANY

The experience of the Brooklyn Union Gas Company offers evidence to refute the contention at page 57 of the National Energy Plan that liquid-based SNG provided the margin of gas supplies that saved residential consumers from curtailment during the winter of 1976–1977. Brooklyn Union's supply situation during the recent winter heating season in fact, enabled it to make large volume sales of SNG produced at its plant to other utilities, since the SNG was not required to meet the needs of Brooklyn Union's own customers. Moreover, through 1976, Brooklyn Union continued adding new residential hook-ups, and sold significant quantities of gas to industrial customers, including interruptible industrial customers that presumably have alternate fuel capability. Possibly the most significant fact is that Brooklyn Union does not anticipate that it will be necessary to operate its plant at full capacity even in the upcoming winter heating seasons, since it projects surplus gas supplies over firm requirements through the 1979–1980 heating season.

Plant history and sales

Brooklyn Union completed construction of its naphtha-based SNG plant in the Spring of 1974. The plant has a design capacity of 60 MMcf of gas per day, permitting production of up to 10,800 MMcf of gas over the 180 day winter heating season during which the plant is intended to operate.[62] As a measure of Brooklyn Union's healthy supply posture, Brooklyn Union produced only 5,885,237 Mcf in

[55] Form G–101–P FEA/FPC Survey on Detail End Use Data attached as Commonwealth Exhibit No. 3.
[56] Attached as Exhibit No. 2.
[57] Virginia Electric Power Co. FPC Form No. 1 attached as Commonwealth Exhibit No. 4.
[58] Footnote 45, *supra*.
[59] Commonwealth Application for Temporary Stay, filed with FEA on January 13, 1977.
[60] *Id.*
[61] Footnote 46, *supra*.
[62] AGA, "Gas Supply Review", Summary of SNG-From-Petroleum Plants (January, 1977); New York 76 Gas Report (Prepared for New York State Public Service Commission by NY Gas Planning Committee In Compliance With Case 25766). (Included as Brooklyn Union Exhibit 1, pp. 1–2).

1976 at its SNG plant, or almost 5,000,000 Mcf less than its plant's design capacity.[63]

The actual volume of SNG produced in the 1976–1977 heating season is unavailable at this time, but the projected volume for this period was 10,200 MMcf.[64] For the next three years, Brooklyn Union anticipates producing only 8,200 MMcf in each of the upcoming winter heating seasons.[65] In part the decision not to operate its plant at design capacity may stem from Brooklyn Union's projection of an actual increase in total system supplies in the next three years, which will result in surplus gas in amounts that are double the planned production of its SNG plant.[66]

Feedstock and cost

Brooklyn Union utilizes naphtha as the feedstock in its plant to manufacture gas with a Btu level of 988 Btu per Mcf. Brooklyn Union has a contract with Exxon which provides for the delivery of 10,000 barrels of naphtha per day during the winter heating season (November 1–April 30)[67] or a maximum quantity of 1,810,000 barrels during this period beginning after July 1, 1975.[68]

The volume of naphtha used for feedstock in Brooklyn Union's plant in 1976 cannot be ascertained, although Brooklyn Union used a total of 1,407,801 barrels in its gas department, presumably in part for feedstock and fuel in its SNG plant.[69] Fuel usage in the SNG facility was reported to be 179,395 barrels.[70] The average cost of the naphtha used for fuel was 0.29 cents per gallon,[71] and the overall average cost of naphtha to the gas department in 1976 was 0.238 cents.[72]

In addition to naphtha used as fuel and feedstock in its plant, Brooklyn uses butane for Btu-enrichment. In 1976, butane use, primarily for enrichment purposes, appears to have amounted to 218,899 gallons, at an average cost of $.1987 per gallon.[73]

The average cost of production of the SNG manufactured at Brooklyn Union's plant is $3.24/Mcf.[74] Brooklyn Union, however, has made short-term sales of SNG to off-system customers at prices ranging between $4.00/Mcf–$5.09/Mcf.[75]

FEA allocation

Brooklyn Union qualified for "grandfather" status under FEA's regulations governing allocations to SNG plants because, as a naphtha-based plant, it had incurred on site expenditures of at least five million dollars on physical construction of its SNG facility prior to May 1, 1974, and had entered into a contract for specific volumes of naphtha. Under the FEA assignment order issued October 31, 1974, Brooklyn Union is entitled to use a total of 2,332,700 barrels of naphtha in the first, second, and fourth calendar quarters, or approximately 12,900,000 barrels of naphtha per day over the winter heating season.[76]

On July 15, 1976, Brooklyn Union requested authorization from FEA to use 700,000 gallons of butane for enrichment in connection with its SNG plant operations.[77] FEA granted this request by a Decision and Order dated October 18, 1976.[78]

Growth, off-system sales, and sales to interruptibles

Brooklyn Union continues to add new residential customers on its system, thereby indicating that it believes its gas supplies are adequate for the future.

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[63] Annual Report of Brooklyn Union Gas Company for 1976 prepared for submission to the New York Public Service Commission, p. G–47. (Brooklyn Union Exhibit 2, at 13).
[64] New York 76 Gas Report. (Brooklyn Union Exhibit 1, at 3).
[65] *Ibid.* (Brooklyn Union Exhibit 1, at 3).
[66] *Ibid.* (Brooklyn Union Exhibit 3, at 1).
[67] *Ibid.* (Brooklyn Union Exhibit 1, at 2).
[68] See Exxon contract included in Brooklyn Union's Petition For Adjustment and Establishment of a Base Period Volume of Naphtha filed July 24, 1974, pp. 15–17. (Brooklyn Union Exhibit 4, at 3).
[69] Annual Report, p. 31. (Brooklyn Union, Exhibit 2 at, 2).
[70] Annual Report, p. G–47. (Brooklyn Union Exhibit 2 at, 14).
[71] *Ibid.* (Brooklyn Union Exhibit 2 at, 14).
[72] Annual Report, p. 31. (Brooklyn Union Exhibit 2, at 2).
[73] Annual Report, p. 31. (Brooklyn Union Exhibit 2 at, 2).
[74] Annual Report, p. G–47. (Brooklyn Union Exhibit 2 at, 14).
[75] See, *e.g.*, Contracts between Brooklyn Union and Piedmont Natural Gas Company, Inc., dated January 11, 1977; Brooklyn Union and South Jersey Gas Company, dated January 22, 1977; Brooklyn Union and Philadelphia Electric Company, dated March 1, 1977; and Brooklyn Union and Pavilion Natural Gas Company, dated February 9, 1977). (Brooklyn Union Exhibits 5a, b, c and d).
[76] Decision and Order for FEA (October 31, 1974). (Brooklyn Union Exhibit 6, at 2).
[77] Application For Assignment, filed July 15, 1976. (Brooklyn Union Exhibit 7).
[78] Decision and Order re: Assignment of Butane, October 18, 1976. (Brooklyn Union Exhibit 8).

For example, in 1976 Brooklyn Union attached an additional 3,294 residential space heating customers.[79] Moreover, Brooklyn Union has continued to sell gas to interruptible industrial customers. Notably, in 1976, Brooklyn Union sold 2,317,121 Mcf of gas to interruptible customers,[80] who, by nature of these contracts permitting interruption of service, presumably have some alternate fuel capability. Combined with Brooklyn Union's sale of 4,503,515 Mcf of gas to firm industrial customers. Brooklyn Union's total industrial load for 1976 was 6,820,636 Mcf/year, or more than the total production in 1976 of Brooklyn Union's SNG plant.[81]

As mentioned earlier, Brooklyn Union has projected gas supply surpluses over requirements in the following amounts: 16,945 Mcf/yr. in 1977–1978; 17,611 Mcf/year in 1978–1979; and 15,921 Mcf/year in 1979–1980.[82] These volumes are in excess of both the maximum capacity of Brooklyn Union's SNG plant, and the lower planned output of the plant for those years. Under these circumstances, it does not appear that SNG production is necessary at all from this plant, and certainly it would not appear to be required to protect residential customers in the forseeable future.

This conclusion is reinforced by Brooklyn Union's sales activities over the last winter heating season. Brooklyn Union reported four off-system sales of its SNG during that period. These sales were as follows:

(*a*) On January 11, 1977, Brooklyn Union notified NYPSC that it had agreed to sell 1,000,000 Mcf of SNG to Piedmont Natural Gas Company, Inc. (cost: $4,00; demand charge $1.25; commodity charge $2.75).

(*d*) On March 1, 1977, Brooklyn Union notified NYPSC that it had agreed to sell up to 500,000 Mcf of SNG to South Jersey Gas Company. (cost: $4.00/Mcf).

(*c*) On February 9, 1977, Brooklyn Union notified NYPSC that it had agreed to sell up to 51,000 Mcf of SNG to the Pavilion Natural Gas Company. (cost: $5.09/Mcf).

(*d*) On March 1, 1977, Brooklyn Union notified NYPSC that it had agreed to sell up to 1,000,000 Mcf of SNG to Philadelphia Electric Company. (cost: $5.09/Mcf).[83]

Storage

By the start of the 1977–1978 heating season, Brooklyn Union will have 11,429,540 Mcf of gas in storage, as a result of storage service provided by Transcontinental Gas Pipe Line Corporation at its Washington Storage Field in Louisiana.[84] The availability of this quantity of gas to Brooklyn Union customers during future heating seasons will more than offset the total production of Brooklyn Union's SNG facility in these periods.

Public Service Electric & Gas Co.

On page 57 of the National Energy Plan, it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information as to Public Service Electric & Gas Company's (PSE&G's) two SNG plants reveals that it is not at all clear that its SNG prevented curtailment of residential users.

While this statement cannot categorically be denied as to PSE&G, there is ample public information indicating that PSE&G's SNG accounts for only 6% of its system supply on a cold day. Therefore, for the statement on page 57 to be accurate, PSE&G would have to have curtailed far more deeply than is reported. Reports from PSE&G in fact indicate that interruptibles were curtailed last winter but that firm customers received only limited curtailment. The 6% of SNG may have helped minimize firm curtailments but there is no indication that it was the margin of gas supply needed for residential service.

Further casting doubt on SNG as being the margin of gas supply that kept residentials warm on PSE&G's system is the fact that PSE&G continues to

[79] Annual Report, p. G–11. (Brooklyn Union Exhibit 2, at 6).
[80] Annual Report, p. G–11. (Brooklyn Union Exhibit 2, at 6).
[81] Annual Report, p. G–11. (Brooklyn Union Exhibit 2, at 6).
[82] New York 76 Gas Reports. (Brooklyn Union Exhibit 1, at 2).
[83] Brooklyn Union Exhibits 5a, b, c, and d; See SEC Form 10–Q, Quarterly Report of Brooklyn Union, filed March 31, 1977, p. 7. (Brooklyn Union Exhibit 9, at 2).
[84] Transcontinental Gas Pipe Line Corporation, Docket No. CP74–33 (Order issued August 31, 1976 and May 27, 1977). (Brooklyn Union Exhibits 10a and 10b).

make sales of gas to itself for electric generation. Finally, if gas supply on the PSE&G system were so tenuous that SNG was the margin of gas required to save residentials, it should not have added 2 Bcf of new customers in 1976. Instead, it should be putting that gas in storage.

SNG production and gas supply

PSE&G has two SNG plants. One plant with a design capacity of 20,000 Mcf/day started production in March 1973. That plant's 1976–77 winter start-up was in January 1977. PSE&G's other plant is designed to produce 125,000 Mcf/day. Its start-up was in December of 1974 with minimal heating season operating. Plant start-up for the winter 1976–77 was in November 1976.

In 1976, PSE&G indicates that its daily design capacity included 1,325,000 therms of SNG per day from its plans.[85] Indications are that a similar level of daily production will occur in 1977.[86] On December 31, 1976, PSE&G's daily gas capacity ignoring curtailments was 19,449,000 therms. On that basis, SNG constitutes less than 7% of its daily design capacity.[87] However, on a cold day, PSE&G to rely on SNG supplies even less. On a cold day, it is estimated that SNG accounts for only 6 percent of PSE&G's gas supply.[88]

While PSE&G reports that it is experiencing curtailments in gas supply from its suppliers,[89] it also reports that in 1976 it added 2 Bcf of new customers.[90] Therefore, the ability to service these new customers must be from rearrangement of its winter load or due to the extra gas made possible by winter SNG production. In either event, the added growth indicates that it is unlikely that SNG is required as the margin of gas supply to keep residentials from being shut off.

Price of SNG

According to news reports, PSE&G has sold its SNG for $5.05 per Mcf.[91] That price was so high that South Jersey Gas Company apparently backed out of a purchase arrangement with PSE&G.[92] It is noteworthy that when PSE&G sells gas to itself for its electric operations, the price is about $1.43[93] not $5.05.

Feedstock

PSE&G's SNG plants are designed to run on 4,000 barrels per day and 25,000 barrels per day of naphtha respectively. The price of the naphtha is reported to be $14.70 per barrel.[94]

Compliance with special rule No. 1

Using Special Rule No. 1 as a guideline, it can be seen that PSE&G's SNG production is out of step. First, PSE&G continues to grow. In 1976, it added 2 Bcf of new customers[95] and still is able to grow under certain conditions. Secondly, PSE&G continues to serve substantial interruptible loads.[96] Although it cannot be determined from available information whether interruptibles were being served while SNG was being produced, the substantial interruptible load, coupled with storage, provides a fair margin of safety for high priority users.

Boiler fuel sales

While it is difficult to pinpoint boiler fuel sales from available public information, it is clear that PSE&G still serves interruptible customers much of the year.[97] In adidtion, 9.5 Bcf of PSE&G's gas was sold to itself for use in its electric generation operations.[98]

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[85] PSE&G Form 10–K for 1976, p. 19 (attached as PSE&G Exhibit No. 1).
[86] *Id.*
[87] 1,325,000 therms of SNG divided by 19,449,000 therms of total gas supply.
[88] PSE&G reports that on a cold day, supplemental gas supplies account for 25 percent of its supply (PSE&G Prospectus, 9/8/76, p. 23 (attached as Exhibit No. 4)). Since SNG is only 25 percent of the supplemental supply, it follows that SNG is only 6 percent of the supply.
[89] PSE&G SEC Form 10–K for 1976, Exhibit No. 1.
[90] *Id.*
[91] Article Energy News, February 24, 1975 (attached as Exhibit No. 2).
[92] *Id.*
[93] PSE&G FPC Form No. 1, p. 432 (attached as Exhibit No. 3).
[94] Source: Texaco, Inc. contract dated September 1976.
[95] PSE&G SEC Form 10–K, 1976, p. 20.
[96] PSE&G FPC Form 1, p. 432.
[97] PSE&G Prospectus, September 9, 1976, p. 23 (attached as Exhibit No. 4).
[98] PSE&G FPC Form 1, page 432 (attached as Exhibit No. 3).

No evidence that residentials were curtailed or in danger of curtailment this winter

Although PSE&G reported near record peak day deliveries, it did not indicate that residentials were curtailed nor that they were in danger of curtailment. The company states that on a peak day, supplemental gas supplies constitute 25 percent of supply.[99] Since SNG is 25 percent of the supplemental supply,[1] PSE&G must rely on SNG for little more than 6 percent of its supply, unless PSE&G curtailed virtually all of its lower priority customers, it is hard to conceive how SNG could have provided the margin of gas supply that kept residential customers from curtailment.[2]

In addition, if there were concern about having adequate supplies for residential and small commercials, PSE&G should not have added new customers requiring an additional 2 Bcf a year or sold 9.5 Bcf of gas to itself for electric generation.

If protection of residentials and small commercials from curtailment is the goal, that objective can be met without the SNG by limiting growth and interruptible sales. At a minimum, there is no indication in available public information that PSE&G's SNG which constitutes only 6 percent of system supply on a peak day provided the margin of gas supply that prevented residentials from being shut off this winter.

Algonquin Gas Transmission Co.—Algonquin SNG, Inc.

On page 57 of the President's National Energy Plan it is stated that the 13 operational liquid-based SNG plants, which include the plant operated by a subsidiary of Algonquin Gas Transmission Company, provided the margin of natural gas supply which saved residential users from curtailment during the last winter. While this statement cannot be categorically denied as applied to Algonquin and its New England service area, there are enough questions regarding Algonquin's use of SNG historically and in the past heating season to warrant a detailed investigation prior to assuming that the production of SNG is necessary to protect residential customers on Algonquin's system.

Since commencing operations of its SNG plant, Algonquin's regular customers have never contracted to purchase from Algonquin its full plant output, forcing Algonquin to turn off-system customers for sale of a portion of its SNG production. This practice continued through the 1976–1977 heating season, and, pursuant to FPC authorization sought by Algonquin, will continue for the next two heating seasons extending into 1979. Moreover, Algonquin's distribution customers continue to add new customers on their systems, a fact that belies a critical gas shortage for high-priority consumers in Algonquin's service area. Finally, in proceedings before the FEA concerning Algonquin's request for a permanent naphtha feedstock allocation, Algonquin has consistently refused to provide FEA with complete data, as specifically requested by FEA, regarding the level of curtailment on Algonquin's and its customers' systems, the end use of the SNG produced by Algonquin, and plans for continued attachment of new loads by Algonquin's customers. These issues, and others relevant to the role played by SNG on Algonquin's system, are more fully discussed below.

History of plant and current sales

Algonquin SNG, Inc., a wholly owned subsidiary of Algonquin Gas Transmission Company, operates a naphtha-based SNG plant in Freetown, Massachusetts. The plant was constructed at a cost of 60 million dollars, and commenced operations in December, 1973. All production from the plant is sold to the pipeline for resale to wholesale customers. Algonquin operates its plant only during the winter heating season pursuant to FPC authorization allowing Algonquin Gas Transmission to render service to its "sale for resale" customers up to the design capacity of the plant (120,000 Mcf/d) for a 151 day period.[3]

In the 1975–1976 heating season, Algonquin produced and sold approximately 17,711,762 MMBtu during the 151 day period of the winter heating season,[4] an

[99] Source: p. 10, PSE&G Annual Report (attached as Exhibit No. 5).

[1] PSE&G SEC Form 10–K, p. 19 (attached as Exhibit No. 1).

[2] PSE&G Prospectus, September 9, 1976, p. 23 (attached as Exhibit No. 4).

[3] Algonquin SNG, Inc., *et al.*, 48 FPC 1216 (1972) and 49 FPC 345 (1973). (Identified as Algonquin Exhibit 1).

[4] Appendix A, Schedule 2 to letter to FPC dated September 15, 1976, submitted in Docket Nos. RP76–15 and RP76–98. (Algonquin Exhibit 2).

amount which fell below the possible plant output by 136,438 MMBtu. It is uncertain whether Algonquin succeeded in selling its entire plant output of 17,848,200 MMBtu in 1976–1977. Prior to the commencement of the heating season, Algonquin's regular system customers had contracted for only 109,625 MMBtu/d compared to plant capacity of 118,200 MMBtu/d.[5] The sale of the remaining 8,575 MMBtu/d of the plant's production was to be made to off-system customers.[6]

However, Algonquin apparently was either unable to sell or deliver its excess SNG, and reported in an application filed with the FPC on February 9, 1977 that it would only have sold 17,347,500 MMBtu of its plant's seasonal production by April 30, 1977, and accordingly requested authority to make the additional 500,700 MMBtu remaining in its seasonal volume available to either its regular on-system SNG customers, or to off-system SNG customer.[7] By order issued March 10, 1977, the FPC granted Algonquin a certificate permitting the proposed supplemental service.[8]

Price

Algonquin Gas Transmission sells SNG for resale pursuant to a separate rate schedule (SNG–1) on file with the FPC. The price for 1976 was between $4.70 and $4.97.[9] The 1977 price was also in this range.[10] However, Algonquin's customers do not price SNG incrementally.[11]

Feedstock

Algonquin uses naphtha as a feedstock in its plant, as well as propane for Btu enrichment. Under a contract with Exxon, Algonquin purchases approximately 4,418,800 barrels of naphtha which is used at a rate of about 29,000 barrels a day during the winter heating season.[12]

Cost of naphtha

Unknown.

FEA allocation

Algonquin is presently operating its plant pursuant to temporary authorization from FEA, which apparently permits Algonquin to use 4,425,571 barrels per year of naphtha. Algonquin has petitioned FEA for a permanent allocation of 4,425,571 barrels per year of naphtha under Section 211.29 and Special Rule No. 1 of FEA regulations.[13] An initial decision granting Algonquin's Petition was reversed by the FEA Office of Exceptions and Appeals and remanded to the Office of Regulatory Programs because Algonquin had failed to establish by record evidence that an allocation of naphtha to operate its SNG plant was necessary to serve high priority customers.[14]

Accordingly, the Office of Regulatory Programs was ordered to make further findings as to three issues: (1) the extent of growth of new gas service in Algonquin's service area, (2) whether Algonquin or its customers had curtailed service to customers in FPC priorities 3–9 with alternate fuel capability, and (3) whether the SNG was sold by Algonquin's resale customers on an incremental basis.[15] Preliminary submissions by Algonquin in response to repeated FEA

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[5] Algonquin Gas Transmission Co., *et al.*, Docket Nos. CP69–41, *et al.*, and Docket No. RP75–88, Order Approving and Adopting Settlement, Consolidating Dockets for Limited Purpose, Amending Certificates of Public Convenience and Necessity, Accepting Tariff Sheets, Ordering Refunds, Superseding Prior Orders, and Terminating Proceedings in Part. (Issued September 17, 1976). (Algonquin Exhibit 3, at 5).

[6] *Ibid.*

[7] Abbreviated Application of Algonquin Gas Transmission Company For a Limited-term Permanent Certificate of Public Convenience and Necessity to Enable the Alleviation of Emergency Gas Shortages, Docket No. CP77–209, filed February 9, 1977. (Algonquin Exhibit 4, at 2).

[8] Algonquin Gas Transmission Co., Docket No. CP77–209 (Order issued March 10, 1977). (Algonquin Exhibit 5).

[9] FPC Form 2 of Algonquin Gas Transmission Company. (Algonquin Exhibit 6).

[10] Letter from W. D. Jaques to Algonquin customers dated February 2, 1977. (Algonquin Exhibit 7, at 2).

[11] See, e.g., letters to William D. Jaques from Bay State Gas Company (February 18, 1977), Cape Code Gas Company (January 19, 1977), Tiverton Gas Company (February 3, 1977), included in submission by Algonquin to FEA on March 4, 1977. (Algonquin Exhibit 8a, b, and c).

[12] Amendment to Exxon Contract dated May 14, 1976. (Algonquin Exhibit 9).

[13] 10 C.F.R. § 211.29.

[14] Petrochemical Energy Group, 3 FEA Par. 80,611 (June 28, 1976). (Algonquin Exhibit 10).

[15] *Ibid.*

requests indicate that certain of Algonquin's distribution customers permit new hook-ups, or expanded gas usage.[16] Algonquin's resale customers do not price the SNG purchased from Algonquin on an incremental basis to their customers.[17]

It should be noted that Algonquin has failed to provide FEA with the data that FEA has requested to enable the agency to proceed with its review of Algonquin's naphtha allocation request. For example, on September 23, 1976, FEA renewed a request originally made May 10, 1976 for data regarding the end-use of gas on Algonquin's system, the extent to which low priority customers of Algonquin have alternate fuel capability, whether Algonquin's wholesale customers price SNG on an incremental basis to their customers, and the nature of expanded gas service anticipated by Algonquin.[18] Again on December 28, 1976, FEA requested this same information from Algonquin.[19] It was not until March 4, 1977 that Algonquin made any meaningful response to FEA's data requests, and even at this time, the information provided was fragmentary and incomplete.[20]

On December 30, 1975, by letter to FEA, Algonquin made application for a permanent right to purchase 50,000 gallons per day of propane for a maximum of 151 days per year (90 days first quarter and 61 days in the fourth quarter) for Btu-enrichment in order to maintain a level of 1,000 Btu per cf of its SNG.[21]

Off-system sales

Since its plant began operation in 1973, Algonquin has never succeeded in selling its full SNG production to regular system customers, and has been forced to make offsystem sales. For the 1976–1977 winter season, Algonquin was authorized by the FPC to make sales of 8,575 MMBtu/d to off-system customers, and contracted to sell SNG to New Jersey Natural Gas Company and Pottsville Gas Co., *et al.*[22] Under a settlement approved by the FPC, Algonquin will continue to make off-system sales in the 1977–1978 winter season and in the 1978–1979 winter season.

Boiler fuel sales

Algonquin sells both system gas and SNG to at least one utility, Orange and Rockland Utilities, Inc., which burned some gas for electric generation in dual-fired boilers during the last winter. For the year ending December 31, 1976, Orange and Rockland reported use of 1,877,725 Mcf of gas for generation of electricity in its dual-fired Lovett plant, purchased at a price of $1.32 per Mcf. For the five month period from November, 1976 to March, 1977, Orange and Rockland reported a usage of 49,200 Mcf of gas on its filed FPC Form 423's for the Lovett plant at a price ranging from $1.08 to $1.44.[23] Thus, while Orange and Rockland is purchasing SNG from Algonquin at almost $5.00 an Mcf, it continues to burn low-priced natural gas as boiler fuel.

Storage

Algonquin has become entitled to certain storage capacity to be made available by Consolidated Gas Supply Corporation to Texas Eastern for benefit of its customers. Under this arrangement, authorized by the FPC,[24] storage capacity amounting to 7,228,000 Mcf will be allocated to Algonquin during each of the 1977, 1978, and 1979 injection periods (April 16–November 15) to be withdrawn at a rate of 58,805 Mcf/d during the winter heating season. This amount is more than half of Algonquin's SNG production, and represents gas available to

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[16] See *e.g.*, letters to W. D. Jaques from South County Gas Company (January 24, 1977); Bay State Gas Company (February 18, 1977); Commonwealth Gas Company (February 4, 1977); Fall River Gas Company (January 17, 1977); North Attleboro Gas Company (February 11, 1977); Tiverton Gas Company (February 3, 1977). (Algonquin Exhibit 11a, b, c, d, e, f). See also SEC Form 10K of Eastern Gas and Fuel Association, the parent of Boston Gas, wherein it is stated that Boston Gas allows a limited increase in load, although it favors customers located on existing mains. (Algonquin Exhibit 19, at p. 8).

[17] Note 9, *supra*.

[18] Letter to W. D. Jaques from George E. Hall, Jr., Director of Product Allocations. (Algonquin Exhibit 12).

[19] Letter to W. D. Jaques from George E. Hall, Jr. (Algonquin Exhibit 13).

[20] Letter from W. D. Jaques to George E. Hall, Jr., (dated March 4, 1977). (Algonquin Exhibit 14).

[21] Letter to Donald E. Allen from W. R. Kane. (Algonquin Exhibit 15).

[22] Texas Eastern Transmission Corporation, *et al.*, Docket Nos. CP77–66, *et al.* (Order issued February 7, 1977). (Algonquin Exhibit 16).

[23] FPC Form 423 of Orange and Rockland Utilities, Inc. (Algonquin Exhibit 17).

[24] Texas Eastern Transmission Co., Docket No. CP77–313, Order issued June 3, 1977. (Algonquin Exhibit 18).

Algonquin's customers in the next three years at a price considerably below the cost of SNG.

Conclusion

Based on the foregoing evidence, the conclusion that Algonquin's sales of SNG were necessary to protect residential consumer from curtailment does not appear warranted.[25] At the very least, the claim that Algonquin's SNG provided the margin of additional gas supplies to same residentials requires further investigation, and Algonquin should be required to demonstrate this fact if it can, as it has so far failed to do to the satisfaction of FEA.

ASHLAND OIL, INC.

On page 57 of the National Energy Plan, it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information as to SNG produced by Ashland Oil, Inc. (Ashland) reveals that it is not at all clear that its SNG prevented curtailment of residential users.

By contract, all of Ashland's SNG is sold to National Fuel Gas Supply Corporation (National Fuel). Although National Fuel services an area of New York that was particularly hard hit by the extreme cold of last winter, there is no evidence that all of the SNG production that became part of National Fuel's gas supply was required to keep residentials warm. The only evidence of curtailment that we are aware of is Emergency Order No. 8 of the Public Service Commission of the State of New York (New York) [26] which mandated 25 percent curtailment of commercial customers over 2,000 Mcf/year during January 1977. Presumably had residentials been threatened, the curtailment of these priorities would have been far more than 25 percent.

Also, National Fuel added customers and says it will continue to add customers in 1977,[27] therefore, to the extent SNG may have helped residentials, it would be serving growth rather than historical users. In addition, it is pointed out that SNG constitutes only 8 percent [28] of National Fuel's total gas supply and on a peak day, SNG (assuming maximum production) makes up only 3 percent [29] of max-day throughput. Hence, there is no apparent basis to conclude that SNG provided the margin of gas that kept residentials warm this winter.

General information as to Ashland's SNG production follow:

SNG production

In 1976, Ashland sold to National Fuel 18,575,683 Mcf of SNG at an average Btu of 990. The current maximum capacity of Ashland's plant is 21 Bcf.[30]

Price

Ashland sold its SNG at $3.2605 per Mcf.[31]

Feedstock

The primary feedstock for Ashland's plant is naphtha produced at Ashland's Buffalo refinery.[32] We understand that Ashland's allocation is 1,279,881 barrels per quarter or 5,119,524 barrels per year. Also, FEA recently has granted Ashland a quarterly allocation of 140,786 barrels of Btu enrichment gas comprised primarily of propylene and propane.[33] As can be seen, Ashland is a substantial consumer of naphtha and natural gas liquids.

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[25] Algonquin's Form 16 filed with the FPC covering the period April 1, 1976 to March 31, 1977 reveals that Algonquin did not attempt to increase its supplies during the last winter by making emergency purchases under either 10 C.F.R. § 2.70 or 10 C.F.R. § 2.68, the existing FPC provisions which authorize purchases by pipelines facing gas shortages. If Algonquin was concerned about curtailing high priority customers, one would expect that Algonquin would have availed itself of this means to increase its gas supply. (Algonquin Exhibit 20).

[26] Attached as Ashland Exhibit No. 1.

[27] National Fuel's Annual Report, 1976, attached as Ashland Exhibit No. 2.

[28] Annual Report to Public Service Commission of the State of New York, page G-32 (attached Ashland Exhibit No. 3. National Fuel Annual Report, *supra*, p. 20. SNG volumes of 18.571 Mcf divided by Total Gas Supply 225,758 MMcf.

[29] 18.571 MMcf of SNG divided by 365 days equals 51 Mcf divided by Maximum day throughput of 1,542 MMcf or 3 percent. Source: Footnote 4, *supra*.

[30] National Fuel Annual Report to New York, p. G-32, attached *supra*.

[31] Ashland Annual Report, *supra*.

[32] *Id*.

[33] FEA Order of April 6, 1977, attached as Ashland Exhibit No. 4.

Comparison of Ashland's actions and special Rule No. 1

Although allocations of naphtha and natural gas liquid feedstock to SNG plants are supposed to meet the criteria of Special Rule No. 1, there is no doubt that Ashland's SNG may be facilitating growth on National Fuel's system.[34] Even industrial sales are ——.[35] Although from National Fuel's Form No. 2 filed with the FPC, it appears that it makes no interruptible sales, it is not clear that the 68,716,073 Mcf sold directly in 1976 to industrial customers[36] went to customers with no alternate fuel capability.

The SNG bought directly from Ashland by National Fuel obviously is priced incrementally, however, National Fuel simply rolls the high cost SNG in with other gas prices. Therefore, whether residentials benefit or not from the SNG, they certainly pay for it.

Off-system sales

National Fuel did make available 6 Bcf of storage service to others indicating that it was not required to meet its own residential customers' needs.

No apparent evidence that residentials and small commercials were curtailed or were in danger of curtailment

As noted earlier, in the midst of the winter, New York imposed Emergency Order No. 8 that mandated a 25-percent curtailment of commercials using more than 2,000 Mcf per year. Such curtailment lasted for 28 days. We are aware of no evidence that indicates residentials were threatened with being cut off.[37] To the extent, SNG were needed for residential services, National Fuels should cease growing rather than attempting to operate with SNG as the potential margin.

Storage capability

During the winter, National Fuel made 6 Bcf of storage service available to others,[38] thereby indicating that such storage was not required for its own residentials. Whether such storage service helped other residentials is unknown.

In short, based on available public information, SNG does not appear to have been the margin of gas needed to keep residentials on National Fuel's system warm, except possibly on two days, this winter.

PEOPLE'S GAS LIGHT & COKE CO.

On page 57 of the National Energy Plan, it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." A review of the publicly available information indicates that SNG production was not the factor which permitted People's Gas Light & Coke Company (People's) to maintain gas service to residential users.

The People's plant is located in Elwood, Illinois and began base load operation in March 1976. Production during 1976 totaled 31.583 Bcf[39] and People's expects production to reach 42.9 Bcf during fiscal year October 1976–September 30, 1977. An output of this magnitude would equal 13.5 percent of the October 1975–September 1976 sales.[40] The plant is designed to run on 33,000 b/d of naphtha.[41]

People's gas sales in the 1976 fiscal year were as follows:

Residential	159.578
Commercial	57.110
Industrial	64.489
Large volume electric generation	9.270
Off-peak	5.445
Interruptible service	15.603
Other gas utilities	5.382
Total	[1] 316.877

[1] Form 10-K at p. 18.

[34] National Fuel Gas Annual Report 1976, attached as Ashland Exhibit No. 2, page 3.
[35] *Id.*
[36] *Id.*
[37] See National Fuel's Interim Report to Shareholders for Period Ending March 31, 1977 attached as Ashland Exhibit No. 5.
[38] Annual Report 1976, p. 6, attached as Ashland Exhibit No. 2.
[39] Annual Report of People's Gas Light & Coke Company to the Illinois Commerce Commission for 1976 at p. 533 (hereinafter "Illinois Report").
[40] SEC Form 10-K, filed December 29, 1976 by People's Gas Light & Coke Company at p. 18 (hereinafter "Form 10-K").
[41] *People's Gas Company,* 3 FEA section 83,215 (June 11, 1976).

People's has agreed to sell 10 percent of the SNG production to North Shore Gas Company, an affiliate. Thus, of the estimated 38.61 Bcf (42.9 times .9) available to People's, approximately 30.318 Bcf will be sold for large volume electrical generation, off-peak or interruptible sales. Another 1.092 Bcf (5.382—4.29 sold to North Shore and excluded above) will be sold to other utilities who also make boiler fuel sales. In sum, it appears likely that all but 7.2 Bcf of this year's SNG production will go to low priority uses not even remotely connected with providing service to residential users. The remaining 7.2 Bcf would service the unspecified "indusetrial" load which undoubtedly includes boiler fuel customers. Thus on the basis of past sales and future SNG supplies, one cannot conclude that SNG is necessary to serve residential users on the People's system.

It is also worth noting that until this past winter, People's had not curtailed any of its customers including the off-peak, interruptible and electrical generation sales.

For a period of less than a month in January–February 1977, People's did curtail industrial and large commercial load by 25 percent. Full service was restored to all customers in February.[42] Even during this limited period of curtailment, approximately 75 percent of the commercial and industrial load was maintained. On an annual basis, this load would be 91.199 Bcf [(57.110+64.489) times 0.75), i.e., more than twice the expected annual SNG production. Thus even in the coldest winter in memory, People's would not have needed the SNG to provide service to residential users.

Although the exact number of new customers is not known, it is clear that People's is continuing to attach new firm load. People's SEC Form 10–Q for the quarter ending December 31, 1976, for example, shows a 3.9 million dollar revenue increase due to additional firm load attachments. Surely, People's would not continue to grow if its SNG plant saved it from curtailing residential customers this past winter. No company that short of gas would continue to add new firm demand.

In short, there is no credible evidence that People's SNG plant was necessary to prevent curtailment of residential users this past winter. In fact, the publicly available evidence indicates that the opposite is true, namely that SNG production primarily allows People's to continue sales to large volume electrical generation, offpeak and interruptible customers.

NORTHERN ILLINOIS GAS CO.

On page 57 of the National Energy Plan it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information as to Northern Illinois Gas Co. (NIGas) reveals that it is not at all clear that SNG from its SNG plant prevented curtailment of residential users.

In fact, review of public information indicates that during the coldest months of the winter, NIGas made substantial sales of gas to Commonwealth Edison for electric generation.[43] Since the SNG production is only 10–11 percent of NIGas' total supply,[44] it is unlikely that NIGas is truly dependent on SNG to service its residential customers. Further, in the winter, NIGas deferred receipt of 160 MMcf per day of gas.[45]

SNG production

In 1976, NIGas produced about 61.4 Bcf of SNG at its SNG plant at Morris, Illinois.[46] That plant start-up was the Fall of 1974. SNG production for 1977 is unknown, however plant design capacity is 55 Bcf per year. The design output constitutes 10–11 percent of NIGas' annual deliveries.[47] Note that SNG production in 1976 exceeded the stated design of the plant by 6.4 Bcf or by over 10 percent.

[42] SEC Form 8–K for February 1977 at p. 2, filed March 14, 1977 by People's Gas Light & Coke Company.
[43] See Northern Illinois Exhibit No. 1.
[44] FEA Decision and Order. Case Nos. FEA–0960, FEA–0967, FEA–0956, issued 2/4/76 and NIGas Form 10–K filed March 31, 1977, attached as Exhibit No. 2.
[45] Northern Natural Gas Co., *et al.*, FPC Docket No. CP76–355, *et al.*, order issued 3/1/77, attached as NIGas Exhibit No. 3.
[46] NIGas SEC Form 10–K filed 3/31/77, see NIGas Exhibit No. 2.
[47] Source, footnote 4, *supra*.

Price of SNG

NiGas rolls the cost of its SNG into total gas costs. Information on precise tailgate costs, is unknown, but NiGas did sell SNG on an emergency basis at $3.785 per Mcf subject to variance for feedstock costs.[48]

Feedstock

NiGas feedstock is supposed to be natural gas liquids (NGLs) and naphtha but now it finds the SNG it produces has such a low Btu content that it needs to enrich the SNG.[49] On a design basis, the plant calls for 32,000 bbls/day of NGLs and 16,000 bbls/day of naphtha.

In recent proceedings (at Attachment B, pp. 9, 15–16) PEG has pointed out that NiGas appears to be receiving a feedstock allocation greater than its own filings have indicated should be required. In addition, NiGas is vastly exceeding its allocation for enrichment uses.

In its November 26, 1974 filing, NiGas estimated its total plant requirements for a year as 14,362,000 barrels.[50] The FEA finally granted an allocation on February 5, 1976, after appeal and remand, of 16,259,500 barrels a year[51] (equivalent to 48,536 barrels a day for a 335-day year). NiGas apparently considered this volume adequate for both feedstock and Btu enrichment uses, for on August 20, 1976, it filed an application in which it asked for total feedstock volumes of 16,259,000 barrels a year.[52]

In its August 20, 1976 Order, FEA granted NiGas the right to use up to 90 percent of the base period volume of 1,500,000 barrels a year (904,500 barrels a year, equivalent to 2,700 barrels a day for a 355-day year), for Btu enrichment during the one year period ending March 31, 1977. This volume was in addition to its feedstock allocation. Despite this limitation, NiGas informed the FEA on January 3, 1977 that it in fact is using enrichment propane at the rate of more than 10,000 barrels per day—equivalent to a yearly volume of 3,685,000 barrels for a 355-day operating year.[53]

Off-system sales of SNG and deferral of deliveries

Further supporting the fact that SNG from NiGas plant was not required to keep its residential customers warm this winter is the fact that NiGas deferred deliveries of 160 MMcf this winter.

An FPC Order (Finding And Order After Statutory Hearing Issuing Certificates Of Public Convenience And Necessity, Granting Petitions To Intervene And Continuing Exemption) establishes beyond question that in the midst of one of the worst winters on record, and in spite of the claims of drastic curtailments of natural gas supplies to high priority users, NiGas is deferring delivery of 160 MMcf per day of natural gas during the winter (12 Bcf aggregate for period December–March) for redelivery to NiGas during the summer.[54] Therefore, during even a most severe winter NiGas had such ample gas supply and storage that it could defer taking substantial volumes of gas.

The volumes of natural gas which NiGas has consented to reschedule equals the total design output of NiGas' SNG plant and shows conclusively that NiGas does not require SNG to serve high priority customers even during the winter heating season. Moreover, the FPC order shows that NiGas will be paid more than $1.00 per Mcf for consenting to this rescheduling. The net result of NiGas' "arrangement" therefore, undisclosed by NiGas in any of its prior submissions to the FEA, would appear to be that (1) SNG costing $3.00–3.50 is being produced and sold to NiGas' high priority customers, while (2) natural gas costing much less is being rescheduled for summer delivery, and (3) NiGas alone appears to benefit at the expense of its customers. There is nothing to indicate that NiGas could not satisfy its high priority customers' requirements with cheaper alternatives than SNG.

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[48] Northern Illinois letter agreement referred to in order of Illinois Commerce Commission attached as NiGas Exhibit No. 4.

[49] FEA order issued April 26, 1977 in Northern Illinois Gas Co., Re: Btu Enrichment, Exhibit No. 5.

[50] Response of Northern Illinois Gas Company to further request for additional information relating to SNG feedstock, November 26, 1974, pp. 4 and 5, and Exhibit 9, Case B.

[51] FEA Decision and Amended Order, February 5, 1976, p. 20.

[52] Petition of Northern Illinois Gas Company for continued SNG feedstock allocational August 1, 1976, Volume I, p. 2.

[53] Letter of L. Raymond Billett, Assistant Vice President, Northern Illinois Gas Company, January 3, 1977, attached as NiGas Exhibit No. 6.

[54] Exhibit No. 3.

Indeed, it can be noted that NiGas regularly participates in the weekly meetings of the Emergency Gas Requirements Group under Emergency Natural Gas Act Administrator Dunham. On March 9, 1977, the Group met to discuss the provisions of Order No. 6. In Order No. 6, Administrator Dunham stated that until April 30, 1977, the term "emergency supplies" permitted to be purchased under Section 6 of the Emergency Natural Gas Act of 1977 will be defined as gas necessary to enable the purchaser to serve uses other than those specified in Priorities 4 through 9 of the FPC Order No. 467, i.e., boiler fuel, and industrial uses with alternate fuel capabilities. Therefore, no pipeline or distributor, such as NiGas, may contract to purchase emergency supplies under Section 6 if, contemporaneously with execution of the contract, the pipeline or distributor is delivering, directly or indirectly, any gas for Priority 4 through 9 uses. NiGas at the meeting urged the lifting of these restrictions apparently because it had acquired additional supplies of gas through SNG, which permitted them to make lower category sales. See Transcript, Emergency Gas Requirements Group, Conference held March 9, 1977, pp. 223–224.

There can no longer be any doubt that while existing nonsubstitutable, high priority users of propane, butane and other liquid hydrocarbons are being denied allocations by the FEA, NiGas has been granted massive allocations, as a new, non-historical, low priority user, so that it can serve boiler fuel customers with alternate fuel capability and can provide service to new customers.

Even certain "emergency" sales NiGas made were to utilities still selling gas for electric generation [55] or did not curtail at all this winter.[56]

Use of boiler fuel

Form No. 423 filed by Commonwealth Edison this winter shows that NiGas sold its gas for electric generation throughout the winter.[57] If they make sales for electric generation, then it is probable they were serving other low priority loads.

No evidence that residentials and small commercials were curtailed

There is no evidence that residentials and small commercials were curtailed. In fact NiGas' Form 10-K filed with the SEC on March 31, 1977, indicates that "its gas supplies will be sufficient to meet the present demand of its firm-year round customers." [58] Further, NiGas continues to add customers thereby evidencing no shortage of gas supply and states it foresees no problems in supplying even the increased load in the future.[59]

Since SNG constitutes only 10–11 percent of NiGas' supply and NiGas projects no firm curtailment, it cannot be said that SNG provided the margin of gas supply required to keep residentials with gas this winter. On the record peak day in January 1977, SNG at maximum production approximately 9% of NiGas throughput.[60] Therefore, SNG could not have provided the margin of gas supply needed to maintain service to residential customers.

COLUMBIA GAS

On page 57 of the President's "National Energy Plan," it is claimed that the thirteen operating SNG plants helped avert a shut-down of residential service in various areas of the country. However, an examination of the facts surrounding the Columbia Green Springs plant and its operations reveals that this is not so. The most that can be said is that the plant may have bailed out the Columbia management from a series of decisions which resulted in near disaster. Not the lack of availability of gas supply, but inadequate planning for the proper utilization of gas supply, appears to have been the foremost cause of the crisis. In fact,

[55] See breakdown of Central Illinois Light Co. (CILCO) attached as NiGas Exhibit No. 6.

[56] Indications from a Mr. Gerald Hoppe of the Illinois Commerce Commission are that CILCO did not have to curtail at all this winter. Similarly, Mr. Hoppe stated that another recipient of emergency gas, Central Illinois Public Service Co., did not curtail its industrial loads.

[57] Exhibit No. 1.

[58] Form 10–K attached as NiGas Exhibit No. 2.

[59] *Id.*

[60] Maximum production of 166,000 Mcf per day divided by maximum day throughput of 1.8 Bcf. (Source: NiGas 10–K attached as Exhibit No. 2).

the circumstances surrounding Columbia's mishandling of this winter's crisis has given rise to at least two complaints before regulatory commissions.[61]

Perspective on the role of SNG on Columbia's system

In the *Metzenbaum* complaint, Columbia is charged with having lifted its curtailment in late September before its storage capacity was full. This lifting of curtailment, when coupled with the unexpectedly early onset of winter weather, resulted in Columbia entering the winter heating season with its storage underfilled some 24 Bcf. Considering that Columbia only expects to produce 66.9 Bcf of SNG in 1977,[62] 24 Bcf is only some 3.8 Bcf than the entire production which woeld be proportionately attributable to the five winter months.

In reply to this complaint, Mr. W. H. Howard, Senior Vice President of Columbia Gas Transmission Company, filed an affidavit in which the admissions are as damaging as the complaint filed against the company by Senator Metzenbaum. For example, Howard states that during September 1976, Columbia had cut back its takes from its Appalachian suppliers to the absolute minimum possible and as of September 20, cut back its deliveries from its Southwestern suppliers by 95,000 Mcf/day. These cutbacks remained in effect until Columbia lifted its curtailment on September 27, 1976.[63]

Despite this excess supply of gas, Howard refers to no attempts by Columbia to reschedule deliveries nor to finish filling its storage capacity before instituting any cutbacks. Nor once colder weather hit in October did Columbia see fit to reimpose curtailment until the formal advent of the winter heating season.

Barter fuel sales of gas

Columbia apparently had earlier opportunities to marshall supplies. The FPC Annual Reports filed by four Ohio electric utilities served by Columbia's Ohio distribution affiliate—Columbia Gas of Ohio, Inc.—show some 2.5 Bcf of gas burned as boiler fuel.[64] If Columbia was serving electric boiler fuel customers, the lowest priority, then clearly it was serving other volume low-priority and boiler fuel uses. Necessarily, the fact that low-priority users were being served in October is evident from Columbia's lifting of all curtailment.

Comparison of Columbia's actions to special rule No. 1

This supplying of low-priority users, many, including the electric utilities, of whom have installed alternate fuel capability, would appear to violate the terms of Columbia's allocation order. It was expressly provided by FEA that no feedstocks assigned by FEA were to be used by Columbia for the manufacture of SNG when any interruptible customers were being supplied with gas. Further, Columbia was to notify FEA at least 30 days in advance of any such sale.[65] Thus, Columbia has not even abided by the terms of its allocation order in lifting its curtailment if its SNG plant continued to operate throughout this period. And query whether Columbia notified FEA of its decision to lift all curtailments at all, much less 30 days in advance? Further, when Columbia was experiencing its purported conditions of excess supply from producers, did it shut down its SNG plant to protect its customers from this high cost source of gas? Or did it maintain SNG production even while refusing lower cost gas from producers?

The complaint filed by the Attorney General of Ohio[66] contains similar allegations, but follows them up with even more damaging allegations. In addition to the improper lifting of curtailment and cut back in deliveries from suppliers prior to the filling of storage capacity,[67] the Attorney General alleges that Colum-

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[61] *Brown v. Columbia Gas of Ohio, Inc.*, Docket No. 77-639-GA-CSS, Complaint filed 4/22/77 before the Public Utilities Commission of Ohio [Columbia Exhibit No. 1]; *Metzenbaum v. Columbia Gas Transmission Corp.*, FPC Docket No. RP77-35, Complaint filed 2/17/77 [Columbia Exhibit No. 2].

[62] Columbia Gas Systems Inc., "Operating, Financial and Statistical Data" for 1976, at 43, on file with the SEC [Columbia Exhibit No. 3].

[63] Affidavit of W. H. Howard, on file with FPC in *Metzenbaum v. Columbia Gas Transmission Corp.*, FPC Docket No. RP77-35, at 1-2 [Attachment to Columbia Exhibit No. 2].

[64] FPC Form 1, filed each by Cincinnati Gas & Electric Co., Dayton Power & Light Co., Columbus and Southern Ohio Electric Co., and Toledo Edison Co., for 1976, at 431-32 [Columbia Exhibit Nos. 4-7].

[65] Decision and Order dated 4/16/76, FEA Case No. FEA-0701, at 15-17 [Columbia Exhibit No. 8].

[66] *Brown v. Columbia Gas of Ohio, Inc., supra* [Columbia Exhibit No. 1].

[67] Complaint, at 11.

bia has instituted onerous billing and pricing procedures which discourage self-help programs by high-priority industrial customers; [68] has discouraged the development of potential natural gas production in the State of Ohio; [69] has avoided purchasing volumes of available self-help gas which industrial customers have not used [70] has failed to develop adequate storage, including offers to lease storage; [71] and has rejected offers of available natural gas suppliers, even while planning residential evacuations due to inadequate gas supplies.[72] One specific offer of gas identified which was rejected was of 50 Bcf on February 1, 1977,[73] in the height of the crisis. Note that 50 Bcf is 75 percent of the entire projected output of the Green Springs SNG plant.

Cost of SNG

In sharp contrast to the praise in the National Energy Plan of the SNG plants this winter, the Attorney General of Ohio attacks the SNG from the Green Springs plant as "an uneconomic fuel." [74] Further, the Attorney General states that Columbia Gas of Ohio's "rolling in the SNG's cost amounts to forced, public subsidization of Columbia's management and is disincentive to its correction." [75]

In regard to costs, the Attorney General compares the $2.25/Mcf cost for gas acquired under the Emergency Natural Gas Act with the $5.00 plus cost of Green Springs SNG.[76]

The forced subsidization referred to by the Attorney General is reflected most clearly in the Form 1's filed by the four Ohio utilities referred to earlier.[77] A review of those filings shows the highest cost gas to be $1.70/MMBtu.[78] Compare this cost to the $5.00 plus cost cited by the Attorney General. Even Columbia admits a cost of $4.14.[79]

SNG production

The fact that SNG was less than critical is reflected in events subsequent to an explosion at the Green Springs plant on January 10, 1977. As a result of this explosion, one of the two trains at the plant was down well over a month.[80] As a result of the explosion and resulting disability of the plant, both Columbia Gas Transmission and Cincinnati Gas and Electric Company received supplemental propane supplies for their propane air plants. This tends to show underutilized propane air facilities which could be used in place of Columbia's Green Springs plant and more efficiently.

The fact is that Green Springs is and has been an unreliable source of supply. The design capacity of the plant is 88 Bcf/year.[81] The 1976 Report of Columbia, however, shows 1976 production at 57.4 Bcf and 1975 production at 44.4 Bcf. As mentioned earlier, 1977 production is estimated at 66.9 Bcf,[82] but the continued validity of even this below-capacity figure is uncertain because of the January 10 explosion.

Feedstocks

Based on past product mixes used,[83] the approximate percentages of natural gas liquids that would be used at design capacity would be 5.5 percent, or 878,570 barrels, ethane, 40.58 percent, or 6,482,249 barrels, propane, 49.62 percent, or 7,926,298 barrels, butanes, and 4.30 percent, or 686,882 barrels, of pentanes and heavier natural gas liquids.

Thus, SNG from the Columbia Green Springs SNG plant did not serve to protect residential users this winter. Rather, it operated when larger, less expensive suppliers of natural gas were available but refused by Columbia. The net effect was to raise the cost of gas to residential users with no compensating benefits.

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[68] Complaint, at 5–7.
[69] Complaint, at 5.
[70] Complaint, at 7–8.
[71] Complaint, at 8–12.
[72] Complaint, at 3–4.
[73] Complaint, at 3–4.
[74] Complaint, at 14.
[75] Complaint, at 13.
[76] Complaint, at 14.
[77] See fn. 4, *supra*.
[78] Form 1 of Dayton Power & Light, Co. *supra*, at 432 [Columbia Exhibit No. 5].
[79] Operating, Financial, and Statistical Data, *supra*, at 43 [Columbia Exhibit No. 3].
[80] Decision and Order of FEA dated 3/4/77 on Modification of Order and Waiver of the Use Limitation on Propane for Peak Shaving, at 5 [Columbia Exhibit No. 9].
[81] Letter from Columbia LNG Corp. to Mr. John W. Weber, FEA dated 2/21/74 [Columbia Exhibit No. 10].
[82] Operating, Financial, and Statistical Data, *supra*, at 43 [Columbia Exhibit No. 3].
[83] Attachment to Letter of 2/21/74, *supra* [Columbia Exhibit No. 10].

CONSUMERS POWER CO.

On page 57 of the National Energy Plan, it is stated that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." Review of public information as to SNG produced by Consumers Power Company (Consumers) reveals that SNG was not responsible for Consumers' maintenance of gas service to residential users this past winter.

Consumers owns and operates a large SNG plant at Marysville, Michigan. This plant currently has a quarterly allocation of 4,605,357 barrels of "propane, butane and/or natural gasoline." [84] Although Consumers uses natural gas liquids (NGL's) for SNG feedstock, the principal source of these liquids is lease condensate exported from Canada. Since lease condensate is a form of crude oil, approximately 70 percent of Consumers' SNG feedstock is subject to FEA's Canadian crude oil allocation program.[85] Due primarily to declining Canadian exports, the Marysville plant has used an average of 40,000 barrels per day,[86] or 3,650,000 barrels per quarter.

During 1976, Consumer produced 59.359 Bcf of SNG and sold 341.087 Bcf of naural gas and SNG.[87] Consumers reports that the total send-out in 1976 was 345.9 Bcf, the difference between total send-out and sales (4.8 Bcf) being attributable to "use and unaccounted for." [88]

In November 1976, Consumers estimated that the SNG cost $3.25–$3.50 per Mcf.[89] Actual figures for 1976 expenditures and production indicate a cost of $3.44 per Mcf.[90] This figure, however, excludes depreciation, taxes and return on plant investment. If one assumes a twenty-year life for the plant and, thus, a 5 percent amortization of the cost each year and a 15 percent return on the outstanding investment each year, the cost of Consumers' SNG is approximately $3.91 per Mcf.[91]

Any evaluation of Consumers' need for SNG must begin with an analysis of the customers served and available natural gas supplies. Such an analysis will show that Consumers did not need SNG to serve any high priority customers in 1976 or the winter of 1976–77. During the past year, SNG was going primarily to boiler fuel customers or other customers who purchase gas under a seasonal rate schedule.

In July 1976, Consumers estimated that it would deliver 33.33 Bcf during 1976 to customers in FPC categories 4–9, i.e. the boiler fuel categories.[92] Although the precise volumes actually delivered to these customers is not known to PEG, a rough approximation can be obtained from figures submitted to the Michigan

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[84] See FEA's "Modification of Decision and Order dated December 12, 1975," issued to Consumers on December 31, 1976 (identified as Consumers' Exhibit A in the Appendix).

[85] Securities and Exchange Commission Form 8–K for the Month of October 1976 for Consumers Power Company at p. 29 (identified as Consumers' Exhibit B in the Appendix).

[86] See Consumers' "Application for Modification" filed with FEA on February 17, 1977, at p. 7 (identified as Consumers' Exhibit C in the Appendix).

[87] Consumers Power Company Annual Report to the Michigan Public Service Commission for the Year Ended December 31, 1976, at pp. 563 and 518D, line 10, column (e); (relevant portions of this report are identified as Consumers' Exhibit D in the Appendix).

[88] Exhibit 2 to Consumers' June 1, 1976 "Application for Adjustment of Base Period Volume—SNG Feedstocks," as revised on May 17, 1977 and filed with FEA on May 27, 1977 (identified as Consumers' Exhibit E in the Appendix).

[89] "Rebuttal Comments of Consumers Power Company," at p. 19, filed with FEA's Office of Regulatory Programs in November 1976 (identified as Consumers' Exhibit F in the Appendix).

[90] Consumers' Exhibit D at p. 563 ($204,107,036 divided by 59,359,472 Mcf equals $3.44/Mcf).

[91] Total plant cost is $156,668,233 (Consumers' Exhibit D at p. 563). Assuming 5 percent amortization in 1973–75, the outstanding investment in 1976 was $133,167,998 (.85 times $156,668,233) and the return on investment would be $19,975,199 (.15 times $133,167,998). The amortization during 1976 would be 5 percent of original investment or $7,833,412.

The total would be:

1976 expenses	$204, 107, 036
Return on investment	19, 975, 199
Amortization of plant	7, 833, 412
Total	231, 915, 647

Total cost of SNG for 1976 equals $231,915,647 divided by 59,359,472 Mcf equals $3.91/Mcf.

[92] Attachment 2 to a letter dated July 13, 1976, to Mr. Corman C. Smith, Assistant Administrator, Regulatory Programs, FEA from O. K. Petersen, Esquire, Managing Attorney for Consumers Power Company (identified as Consumers' Exhibit G in Appendix).

Public Service Commission (MPSC). MPSC defines "seasonal" usage as that subject to a possible 90-day interruption.[93] Obviously, a firm which buys gas with the possibility of a 90-day curtailment either has installed alternate fuel capability or doesn't need the gas powered unit at all. PEG submits that any firm which could withstand a 90-day curtailment could do without gas by purchasing larger qantities of its alternate fuel. Consumers reports that it sold at least 30,694 Bcf in 1976 to "commercial and industrial seasonal users."[94] Consumers also sold 6.245 Bcf to itself, primarily for electrical and steam generation which is defined by the FPC as "boiler fuel."[95] Thus, it appears clear that Consumers sold at least 36.939 Bcf to customers with boiler fuel uses or to customers buying gas at lower rates with the possibility of a 90-day curtailment.[96]

Turning to the gas supply side of the equation, it appears that Consumers had more gas available in 1976 than demand. Figures submitted by Consumers to the MPSC show a total supply of 407.086 Bcf.[97] These numbers are roughly consistent with those supplied to FEA in Consumers' Exhibit E, except the MPSC figures do not reflect the 10.1 Bcf of spot purchases and the Consumers' Exhibit E figures do not show the storage gas or "Btu stabilization" gas that appear in the MPSC annual report. Correcting the MPSC figure to include the spot purchases, Consumers' available gas supply was 417.187 Bcf in 1976.

Comparing supply with demand, it is apparent that supply exceeded demand in 1976 by 71.187 Bcf (418.087—345.9). Since the SNG plant contributed only 59.359 Bcf, it is obvious that Consumers could have served all of its customers without any SNG. This course of action, however, would have greatly depleted the storage supply. To avoid this result and avoid the use of SNG, Consumers would have needed to curtail the boiler fuel and seasonal customers who bought 36.939 Bcf. If these customers had been curtailed, Consumers' demand would have been 308.961 Bcf (345.9—36.939). Consumers' supply, excluding SNG and storage gas, was 287.012 Bcf [417.186—(59.359+70.815)]. To make ends meet, this past year Consumers would have needed to use 21.949 Bcf (308.961—287.12) from storage. This volume represents only 30 percent of the available gas storage reported by Consumers. It is clear from these annual figures that SNG was not necessary to serve high priority customers this past year.

The statement at page 57 of the National Energy Policy focuses on the role played by SNG plants this past winter. While there is no data available which details Consumers' sales this past winter by FPC category, it can be observed that Consumers (*a*) had sufficient gas to continue boiler fuel sales and (*b*) apparently did not curtail any of its customers, even those in FPC categories 4 and 5.

The FPC Form 423's for November 1976—March 1977 reveal that Consumers sold 4.971 Bcf during this period for electrical generation.[98] Thus, it appears that a significant portion of the SNG produced in the winter went to the electrical generating equipment of Consumers and Detroit Edison Company. Moreover, Consumers' peak day for deliveries was in December 1976 and the consecutive 3-day peak was in January 1977. Yet, Consumers reports that it experienced no curtailment during this period.[99] If a firm is delivering peak volumes, experiencing no curtailment and serving boiler fuel and electrical generation loads at the same time, it is obvious that the high priority customers are not in danger of curtailment. The SNG plant's average daily production was .162 Bcf (59.359 divided by 365) in 1976. Assuming a higher rate of .190 Bcf for the peak days, the SNG production was only 8.3 percent (.190 divided by 2.284) of peak day deliveries.

Thus, during this winter's coldest day, SNG provided service to the bottom 8.3 percent of Consumers' total system, that is the large volume boiler fuel and electrical generation loads. In light of these facts, one cannot seriously suggest

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[93] Consumers' Exhibit D at p. 518B.

[94] Id. at p. 518D, line 5. Note that some 5.061 Bcf were sold but unbilled as of January 1, 1977 and therefore were apparently not assigned to any particular rate schedule. Some of this 5.061 Bcf should be attributed to Rate Schedule E customers, i.e. the seasonal customers.

[95] Consumers' Exhibit D at pp. 523 and S–6, line 43; 18 C.F.R. section 2.78(c)(9).

[96] The revenue figures on Consumers' Exhibit D at p. 518D indicate that on a per Mcf basis, the Rate Schedule E gas is the lowest price gas sold by Consumers.

[97] Consumers' Exhibit D at p. 568.

[98] The relevant Form 423's are identified as Consumers' Exhibit H in the Appendix.

[99] Consumers' Exhibit D at p. 565.

that it was the SNG plant which kept homes, offices or even high priority industrial uses in operation this winter on the Consumers system.

Further evidence of the fact that Consumers does not need SNG for residential uses can be found in the electrical side of the company. Consumers operates seven peaking units; three are gas-fired only, two are oil-fired only, and the two largest apparently can use oil or gas.[1] The two oil-fired plants were run only 475 and 464 hours respectively for the entire year. By contrast, the gas-fired and partial gas-fired plants were run an average of 2,847 hours. Moreover, in the plant most heavily utilized, which used both oil and gas, Consumers burned 135 times as many Btu's of gas as oil. In the largest unit, Consumers burned 4 times as much gas as oil.[2] If Consumers needed SNG to serve high priority uses, it certainly would not be running its gas-fired electrical generation equipment 6 times as much on an hourly basis as the oil-fired equipment, nor would Consumers use more gas than oil in the apparently dual-fired units.

The reason Consumers uses the gas-fired equipment is economic. The gas costs Consumers an average of $1.54 per Mcf or $1.56 per MMBtu. Even the SNG which Consumers received from itself carried an average price of only $1.75 per MMBtu.[3] Oil, however, cost approximately $13.30 per barrel or $2.30 per MMBtu. Since the SNG cost at least $3.44 per Mcf, Consumers is able to get its gas customers to subsidize the cost of electrical generation. Thus, Consumers has great incentives to continue to burn SNG for electrical generation. If SNG were priced incrementally, this would not be the case.

If SNG were needed during the past winter or year to serve residential users, one would think that Consumers would be in a no-growth posture. Yet, this is not the case. In 1976, Consumers added 20,928 new residential space heating customers and 562 new commercial space heating customers.[4] These customers represent a *new* demand of approximately *4.241 Bcf per year.*[5] Consumers is presently adding new customers and hence new demand.[6] Conduct of this sort does not indicate that it was only the fragile SNG supply based on dwindling Canadian feedstocks that kept the homes in Michigan warm this witner.

Consumers' sales of boiler fuel have even prompted the Federal Power Commission (FPC) to deny Consumers access to natural gas supplies developed in the offshore Louisiana by Consumers' subsidiary, Northern Michigan Exploration Company (NOMECO).[7] The FPC found that: ". . . the effect of adding the NOMECO volumes will primarily be to *augment* Consumer's ability to serve the large volume boiler fuel loads in priority 5. . . ."[8]

By Consumers' estimate, this decision will preclude its access to 52.5 Bcf of proved reserves and an additional 165 Bcf of probable reserves in the offshore Louisiana which it paid to find and develop.[9] Obviously, the FPC would not have denied Consumers the benefit of its investment if the gas had been destined for a use compatible with the public convenience or necessity. Thus, Consumers' SNG plant and its boiler fuel sales of that gas have denied it and its consumers access to large, relatively inexpensive offshore reserves.

The preceding discussion has focused on 1976 and the 1976–77 winter. The future looks even better from a gas supply standpoint and, thus, provides even less justification for SNG. Consumers is presently predicting a surplus of gas

[1] Annual Report of Consumers Power Company to the Federal Power Commission for the Year Ended December 31, 1976 (FPC Form No. 1) at pp. 432C–E (identified as Consumers' Exhibit I in the Appendix).

[2] *Id.*, *see* line 7 for hours of operation; line 38 for quantity of fuel burned; line 39 for Btu value per unit of fuel burned; and line 40 for laid-in cost of fuel.

[3] From the FPC Form 423's one can determine that the B.E. Morrow and Thetford units receive gas from Consumers.

[4] Consumers' Exhibit D at p. 518–A, line 7.

[5] Consumers' Exhibit D at p. 518–C, lines 3 and 6, column (e) shows that the average annual space heating use in 1976 was 182.82 Mcf per residential and 1,195.42 Mcf per commercial customer. Since Consumers' Annual Report to the shareholders stated that 1976 was 5.5 percent colder than the 30-year average, the usage figures given above were lowered by 5.5 percent to 172.29 Mcf and 1,129.67 Mcf respectively. Multiplication of these usage figures by the number of new customers in each class, as per p. 518–A of Exhibit D, results in the demand figure referenced above.

[6] FEA Hearing Transcript at p. 78, In Re: *Petrochemical Energy Group*, Case No, FMR-0102 (June 2, 1977) (identified as Consumers' Exhibit J in the Appendix).

[7] *Michigan Gas Storage Co. et al.*, FPC Docket No. CP74–322, *et al.* (Order of January 11, 1977) (identified as Consumers' Exhibit K in the Appendix).

[8] *Id.* at p. 8.

[9] Consumers' "Application for Rehearing," in FPC Docket No. CP74–322, at p. 15, filed February 10, 1977 (identified as Consumers' Exhibit L in the Appendix).

in 1977 and a larger surplus in 1978.[10] Note that on the supply side, Consumers shows no spot purchases which contributed 10 Bcf in 1974 and in 1976.[11]

If the SNG plant were shut-down on June 30, 1977 having produced one-half of the yearly total, and if Consumers began purchasing spot gas at the same rate it did in 1974 and 1976, the supply forecast could be restated as follows:

Supplies (Bcf):	
Trunkline contract volume	255.5
Panhandle contract volume	92.5
Michigan production	52.8
Marysville SNG	20.55
Spot purchases	5.05
Subtotal	426.4
Less pipeline curtailments:	
Trunkline	81.7
Panhandle	18.9
Total supply	325.8

Total supplies of 325.8 Bcf, not including Consumers' considerable storage volumes, would be only 2.5 Bcf less than the estimated demand of 328.3 Bcf. This shortfall, 2.5 Bcf, is less than the shortfall actually experienced in 1976.[12] Thus, Consumers could lose its SNG plant for the remainder of the year and still serve the 36 Bcf of boiler fuel, electrical generation and seasonal load it served in 1976. This fact demonstrates beyond doubt that residential users on Consumers' system were not dependent upon SNG in this winter nor will they be in the foreseeable future.

The CHAIRMAN. Next, we will hear from Mr. Herbert Brown, counsel, California Energy Resources Conservation and Development Commission.

STATEMENT OF HERBERT H. BROWN, COUNSEL, CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

Mr. BROWN. Mr. Chairman, members of the committee, I am Herbert H. Brown, an attorney in Washington, D.C. and counsel for the California Energy Resources Conservation and Development Commission. Chairman Maullin regrets that he cannot be here to present his testimony personally. Pressing business in California kept him out there, so he asked me to present his testimony.

I would appreciate that the statement of Chairman Maullin be inserted in the record.

Chairman Maullin generally supports the tax provisions of the National Energy Act of 1977 (H.R. 8444), including the Ketchum-Hannaford and the Moffett Ad Hoc Committee amendments. Under the Ketchum-Hannaford amendment, the crude oil equalization tax would vary according to the type, quality, and location of the oil. The Moffett amendment allows public utility commissions to determine the disposition of rebates to utilities resulting from the oil and gas user tax program.

Chairman Maullin urges this committee to retain the language of section 4992 which provides exemption from oil and gas consumption taxes where coal use or conversion is precluded and requires consulta-

[10] Consumers' Exhibit E.
[11] *Id.* and the original Exhibit 2 to Consumers' June 1, 1976 Application for an Assignment of SNG Feedstocks (identified as Consumers' Exhibit M in the Appendix).
[12] *See* 1976 actual supply/demand figures in Consumers' Exhibit E.

tion of the Secretary of the Treasury with appropriate Federal and State agencies.

Consultation with the EPA and State air pollution control authorities would insure that no facility will be taxed for not converting because it was prohibited from doing so by a State or Federal law. In the near future—the next 10 years—it would be impossible to burn coal, using present technologies, in the southern California air basins. In northern California, where it may be possible, the first applications for in-State coal-fired powerplants are expected from Pacific Gas & Electric Co. this fall.

Conversion of existing oil-fired thermal electric generating plants to coal in any part of the State would be virtually impossible over the short term. California's existing oil-fired plants—about 20,000 megawatts—were designed to operate on oil and natural gas. Converting these plants to coal use would entail prohibitive costs—in the range of $5 billion—with no increase in capacity. During a 1- to 3-year conversion period, significant amounts of generating capacity would be off-line, possibly impairing reliability of service for extended periods of time. Environmental, land use, transportation, and fuel supply factors would further complicate the conversion process.

Chairman Maullin urges only three modifications to the bill before this committee. First, that this committee expand the definition of "alternative energy property" to include utility investment in conservation measures other than coal conversion to be eligible for oil and gas conservation rebates from the oil and gas user taxes.

The proposed utility oil use tax would add another $200 to $300 million to ratepayers' bills. State regulatory commissions would have to decide whether or not to permit the utilities to pass these additional costs through to ratepayers. Utilities could receive credits against "alternative energy property" as defined under section 4998 of the bill.

This definition of "alternative energy property" is significant because, according to plans filed by the utilities with the California Energy Commission, the utilities are already planning on substantial reductions in oil-fired capacity and on increased reliance on coal. Oil currently provides nearly 60 percent of California's total generating capacity, at about 20,000 megawatts. Due to high fuel costs, over 1,000 megawatts of oil diesel- and distillate-fueled capacity will be retired by 1985 and over 4,000 megawatts—about 10 percent of present capacity and about 20 percent of present oil-fired capacity—will be retired by 1995.

Coal-fired capacity is already projected to more than double by 1985, and to increase fourfold, to about 8,700 megawatts, by 1995. More than half of the increase in coal capacity is planned for out-of-State projects, which are affected both by Federal and by other States regulatory policies. Finally, the pressure to further expand coal-fired capacity could increase significantly, to the extent that the utilities' planned reliance on nuclear power for 60 percent of all new capacity additions over the next 20 years may prove to be unrealistic.

Section 4998, which includes a definition of "alternative energy property" for purposes of the credit against tax on business use of oil and gas provides for a rebate for "fuel-switching or coal-conversion." It does not provide a rebate for utility investments in solar energy devices or conservation measures which would improve the efficiency of fuel use and/or reduce baseload and peak demand (insulation, load management). These should also be eligible for a true "conservation" rebate and included in the definition as "alternative energy property."

Second, Chairman Maullin urges that this committee permit intangible drilling cost expenses as a tax deduction for geothermal resources, that the depletion allowance for geothermal resources be increased to 22 percent, and that the adjusted cost limitations be removed for the following reasons:

One, of the combination of these tax incentives would reduce the price of steam at The Geysers by approximately 6 mills/kilowatt-hour—from 18.5 mills to 12.5 mills—and the bus-bar cost of hydrothermal (hot water) power approximately 9 to 15 mills/kilowatt-hour, depending on the location and temperature of the resources—a 20-percent reduction in currently estimated costs.

Two, such tax incentives would place geothermal resources on a tax level comparable with other energy resources and hence would improve the perception of risks to the private developer. Actual costs to the developer would be reduced by as much as 10 to 15 percent.

Three, most important, such tax incentives would substantially increase the quantity of hydrothermal electric power which may be economically developed from the users point of view. This would result in an increase from 9,000 megawatts to 15,000 megawatts of geothermal generated electricity which could be economically produced by the year 2000.

Third, Chairman Maullin urges this committee to provide an "alternative energy fund" rebate to States from crude oil equalization taxes imposed on State owned oil production. We believe that such rebates should be equal to the Federal revenues derived from the crude oil equalization tax on oil produced from State-owned lands and should be earmarked for use only in State administered alternative energy funds. Such funds would provide a critically needed source of low interest loans and direct grants in aid to low income groups which cannot take advantage of the administration's income tax credits for conservation measures and solar energy installations. In special circumstances, such funds could also be used for the enhanced recovery of additional oil production from State owned lands. California and other States have had experience in administering similar loan and grant programs for pollution control equipment to small firms which normally cannot afford pollution equipment.

Oil produced from State-owned lands is an important source of income for States. Federal crude oil equalization taxes will deprive States of the true value of their resources and could induce some to withhold their resources—badly needed by the rest of the Nation—if their benefits were to be inequitably distributed.

A rebate of the equalization tax—or some fraction thereof—on State-owned and produced oil would provide a sufficient incentive for States to continue to produce and at the same time provide the resources to get them off the oil and gas "habit."

The House Ways and Means Committee has already established the principle of and recognized the need for special consideration of regional needs by adopting the "heating oil rebate" concept—which will benefit New England the most—from funds derived from the equalization tax. We believe that it is only equitable to allow a small portion of this same tax to be returned to States from which the oil is produced. The rebate system described above for the return of Federal tax revenues to the producing States would accept and build upon the basic conceptual structure of the bill before the committee.

As an alternative to this approach, oil produced from State-owned lands could be exempted from the equalization tax. If this alternative were selected, then a condition should be made by Congress that a substantial portion of increased moneys received by the producing States for their oil should be devoted to energy conservation purposes and the development of energy alternatives.

Producing States have historically relied heavy on oil and gas, and especially gas, for residential heating purposes. Now that gas prices will increase, it is important for the tax system to assist in expediting a transition to an energy frugal and solar energy era.

If the committee staff should wish us to prepare specific statutory language in pursuit of the matters discussed above, we will, of course, be pleased to so respond.

Thank you for your consideration.

The CHAIRMAN. Thank you very much for your statement.

One thought occurs to me. We have a lot of gas in Alaska that we need to bring to the lower United States. Whether we can work it out with the Canadians to pipe it across Canada is a real question mark. But we are told that Californians do not want to permit that gas to come ashore in California and be pumped across California. The pipeline is already there. All you have to do is reverse the direction and push the gas across California through the rest of the United States and bring it into the Texas area. The pipelines there connect to Louisiana, our pipelines connect with the whole eastern seaboard, Chicago and Indianapolis as well as other areas.

We would have no objection at all to pushing that gas across Louisiana. We are cooperating to solve this problem. If we are going to try to help California with its problems, it seems to me that California ought to be able and willing to help the Nation with the Nation's problems. California should cooperate in bringing gas into the United States and pushing it through their pipeline, so that the rest of the country can benefit.

There is no reason why California could not use some of that gas for their own generators, and solve some of the environmental problems you have in California. Natural gas is the cleanest fuel.

If we are willing to put up with the problems of energy transportation in Louisiana, why cannot you people in California cooperate?

Mr. BROWN. Mr. Chairman, I am not prepared to respond on this particular question. I will certainly take back your thoughts and make sure that they are in the hands of appropriate people.

The CHAIRMAN. See if you can think of an answer to it.

Mr. BROWN. I am quite certain that the State of California and the officials there are acting in pursuit of what they believe is in the best interests of both the country and the State. I doubt they would be willing to stipulate that they are not cooperating with the efforts of other States and the Federal Government.

[The following was subsequently supplied for the record. Oral testimony continues on p. 468.]

ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSON,
Sacramento, Calif., August 22, 1977.

Hon. RUSSELL B. LONG,
Chairman, U.S. Senate Finance Committee,
Washington, D.C.

DEAR CHAIRMAN LONG: In response to your question at the August 12, 1977 Senate Finance Committee hearing, California has no objection to permitting gas to come ashore and be pumped across California to the rest of the United States.

We are not opposed to sharing natural gas supplies with the rest of the country. Our concerns, rather, lie in ensuring that the liquefied natural gas (LNG) terminals that would be necessary are located in remote areas and are designed to operate safely and reliably. Governor Brown and the leadership of the California Legislature are on the verge of enacting legislation to expedite site selection and permitting requirements necessary to ensure that a safe and reliable LNG terminal can be constructed in California in the early 1980's. I am enclosing a copy of Governor Brown's letter to President Carter on the Alaskan gas transportation system, along with a resolution passed by the Energy Commission on LNG.

California also has no objection to the transport of Alaskan crude oil through the State to the rest of the country. I am enclosing a copy of a joint statement made by Tom Quinn, Chairman of the California Air Resources Board and Robert Batinovich, President of the California Public Utilities Commission, on the proposed SOHIO–BP oil tanker terminal in California. As their statement indicates, California is concerned with the air emissions associated with the oil terminal and the impacts that the conversion of the El Paso pipeline would have on California's ability to receive natural gas supplies from Mexico or Canada. The state, however, is involved in ongoing negotiations in an effort to ensure that Alaskan crude oil supplies are available to the other states.

I hope that I have responded to any questions you may have had on California's position on the transport of Alaskan oil and gas. We also appreciate the opportunity that you have given us to present our views and recommendations on the National Energy Act.

Sincerely,

RICHARD L. MAULLIN, *Chairman.*

Enclosures.

STATE OF CALIFORNIA,
GOVERNOR'S OFFICE,
Sacramento, June 30, 1977.

The Honorable JIMMY CARTER,
The White House,
Washington, D.C.

DEAR PRESIDENT CARTER: The Alaska Natural Gas Transportation Act of 1976 provides that Governors may recommend to you by July 1, 1977, their preferred transportation system for delivery of North Slope Alaskan gas to the contiguous United States.

The route selection and method of delivery for North Slope gas are of prime importance to California. Our environment and our economy both depend heavily on natural gas and our traditional sources of domestic supply are running low.

Generally, I believe that delivery of North Slope gas by overland pipeline through Canada, with a direct spur (or "western leg") to the Western states, is the most timely, least costly, and most environmentally sound option.

However, since the future of both the Arctic and Alcan pipeline proposals depend almost entirely on pending decisions by the Canadian National Energy Board and the Canadian Government, I believe it would be premature for me to express a preference among the three competing proposals before the proper authorities of Canada have spoken on this issue.

Sincerely,

EDMUND G. BROWN, Jr., *Governor.*

[Resolution No.: 76-1117-131]

STATE OF CALIFORNIA

STATE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

Resolution

Whereas, the California Public Utilities Commission has been directed by recent state legislation (SB 2008) to "represent the united interests" of (state agencies) in federal regulatory energy proceedings and to consult with state agencies, specifically the ERCDC (Section 5401 of the Public Utilities Code); and

Whereas, the ERCDC staff has prepared or in preparation comprehensive reports designed to identify emerging trends related to energy supply, demand, and conservation and public health and safety factors pursuant to Section 25309 (the Warren-Alquist Act) "to provide the basis for state policy and actions in relation thereto"; and

Whereas, ERCDC staff has acquired and analyzed information in order to ascertain future energy problems and uncertainties including:

(*a*) The production of Alaskan North Slope oil and its projected use in the State;

(*b*) Impacts of petroleum price increases and projected conservation measures on the demand for energy and indirect effects on the need for offshore oil development and Alaskan oil delivery into the State;

(*c*) Potential shipments of Alaskan oil through the State;

(*d*) The impact on the State of national energy policies including Project Independence and its successors; and

(*e*) Implications of natural gas decisionmaking for California;

in accordance with Section 25005.5 of the Public Resources Code (SB 1479); and

Whereas, the CPUC, in consultation with the Governor's Office of Planning and Research and ERCDC staff, has established procedures for consultation with other state agencies in federal energy proceedings; and

Whereas, the CPUC will file a final brief in the El Paso Alaska case by November 30, 1976, which will set forth a statement of policy, based upon the record before the FPC, of other state agencies (CPUC telegram, October 28, 1976): Therefore be it

Resolved, That the General Counsel's Office, in coordination with the Executive Director and Commission staff, shall recommend to the Commission appropriate responses to CPUC's request for assistance and to have evidence, expert witness(es), and statements of policy prepared when appropriate for the following federal regulatory energy proceedings (described in depth in attachments) pursuant to the ERCDC's consultation responsibilities according to the provisions of SB 2008:

(1) El Paso Alaska Company, FPC Docket No. CP75-96, *et al.;*

(2) Pacific Indonesia LNG Company, FPC Docket No. C75-160, *et al.;*

(3) El Paso Natural Gas Company, FPC Docket No. CP75-362;

(4) Proposed Rulemaking for Approved States' Coastal Zone Management Program, FPC Docket No. RM76-38;

(5) Request for Rulemaking on LNG Site Selection Criteria, FPC Docket No. RM76-13; and

(6) Pacific Alaska LNG Company, FPC Docket No. CP75-140;

be it further

Resolved, That all statements of policy representing the position of the Energy Resources Conservation and Development Commission in any of the above federal energy regulatory proceedings be submitted on the Energy Commission's consent calendar and approved before they shall be officially represented as a Commission position; be it further

Resolved, That the Energy Commission makes the following Alaskan North Slope natural gas policy findings, and respectfully requests the California Public Utilities Commission to include these findings and the attached policy statement in its final brief in the El Paso/Alaska case and consider them in the development and approval of CPUC's own final arguments:

(1) That California will require at least one liquefied natural gas (LNG) regasification marine terminal in the early 1980's;

(2) "Until the risks inherent in liquefied natural gas terminal operations can be sufficiently identified and overcome and such terminals are found to be consistent with the health and safety of nearby human populations, terminals shall be built only at sites remote from human population concentrations. Other unrelated development in the vicinity of a liquefied natural gas terminal site which is remote from human population concentrations shall be prohibited. At such time as liquefied natural gas marine terminal operations are found consistent with public safety, terminal ties only in developed or industrialized port areas may be approved." (California Public Resources Code, Section 30261(b).)

(3) That given the current state of knowledge concerning LNG safety, the proposed Oxnard and Los Angeles LNG terminal sites should not, at the present time, be considered "remote from human populations concentrations";

(4) That the State of California has a law and a process (the California Coastal Act, SB 1277) for resolving LNG-related land use, environmental, and safety questions and for issuing coastal permits for LNG terminals;

(5) That it would be inappropriate for California to advocate a specific remote site (on or offshore) until such time as the state has completed its environmental impact, supply contingency, and seismic and LNG safety studies;

(6) That certification of an overland natural gas pipeline system is in California's and the national interest, in part because diversification of supply sources minimizes risks and enhances the reliability of energy delivery systems; and

(7) That, however, if the Federal Power Commission should approve the El Paso Alaska proposal and must, therefore, select one of the three proposed California sites in the *El Paso/Alaska* proceeding, it should tentatively approve a site subject to:

a. Permit approval by the State Coastal Commission and review by the State Seismic Safety Commission;

b. Strict permit conditions which prohibit unrelated secondary (or induced) industrial and residential development adjacent to the site or within a "fire hazard" radius of the site: and

c. Completion and evaluation, including public hearings of the expanded alternate site analysist for the Point Conception EIR.

Therefore, be it

Resolved, That the Energy Resources Conservation and Development Commission finds that an overland pipeline delivery system for natural gas from Alaska's North Slope including a western leg for direct delivery to California should be selected by the Federal Power Commission which most closely incorporates the following characteristics:

(1) Earliest possible completion date;

(2) Lowest cost of service;

(3) Least environmental impact particularly including impact on sensitive wildlife areas;

(4) Provides access to the largest deliverable natural gas supplies;

(5) Relies on proven pipeline construction techniques;

(6) Maximizes the use of existing rights-of-way;

(7) Provides an acceptable financing plan requiring the least possible governmental subsidies;

(8) Provides the most direct delivery system for California;

(9) Enjoys the committed support of both the United States and Canadian governments;

(10) Provides the greatest incentives for maintaining continued access to Canadian gas already contracted with California consumers.

Whereas the final decision on the choice of systems for delivering Alaskan North Slope (and Canadian) natural gas to the lower 48 states will be made by the President with Congressional concurrence in the second half of 1977; be it

Resolved, That the SERCDC directs the staff to prepare issue papers in support of hearings to be held by the CERDCD during the 1st quarter of calendar year 1977. The purpose of the hearings shall be to enable the Commission to take a definitive position in favor of one or the other of the overland gas transportation routes for North Slope gas and to communicate such findings to the President and the Congress.

Dated: November 17, 1976.

State Energy Resources Conservation
and Development Commission,
Richard L. Maullin,
Chairman.

[Attachment to Resolution No.: 76-1117-13]

ENERGY COMMISSION POLICY STATEMENT—EL PASO/ALASKA CASE

The Energy Commission contends that the CPUC acted prematurely in choosing Oxnard as the preferable site for the El Paso/Alaska project for the following reasons:

(1) The public safety factor regarding the proposed facilities at Point Conception, Oxnard and Los Angeles Harbor is still undetermined. The risk assessment studies prepared by Science Applications,, Inc. (SAI) for all three facilities and submitted for the record by Western Terminal as Exhibits WL-51, WL-52, and WL-53 were based on preliminary data and anticipated design (Tr. 25178). The SAI studies were published in December 1975, and do not fully reflect certain critical engineering details and design progress. For example, seismic analysis for the Oxnard marine facility was completed in July 1976, and the related gimbal joint study was completed in September 1976.

(2) Disagreement exists between the FPC staff and SAI regarding the behavior of LNG vapor clouds and other key risk determinants, such as marine vessel traffic. Attention is directed to a letter from the FPC staff to Western Terminal, dated October 26, 1976, in Western LNG Terminal Company, Docket No. CP75-83-2, requesting additional information as to 21 technical points relating to the SAI risk assessment studies and models and assumptions upon which those studies were based. The information requested in this letter indicates that several important areas relating to public safety remain unanswered.

(3) Witnesses for Western Terminal stated that they were convinced "internally" that the proposed facilities "presented no undue hazard to the public" and that SAI's risk assessment studies were performed primarily for "defense in permit proceedings", and for the purpose of "convincing the public" (Tr. 24959). Witnesses for SAI stated that no changes in design or operations were suggested because "the risks were extremely low and therefore there was no reason to suggest any changes in the design". Western Terminal did not produce "internal" studies or documents which led them to the conviction that the facilities were acceptably safe, prior to completion of the SAI assessment studies. Therefore, the SAI work must be treated as an advocacy document until such time as technical review by qualified, independent peers has established its scientific validity. This review process has only just begun. SAI's conclusions and methods have not been shown to enjoy general acceptance in the scientific community, and they have not been accepted or relied upon by any identifiable authority other than Western Terminal.

(4) Contingency planning appears woefully inadequate to assure public safety in the event of a major safety incident, however unlikely.

(5) Pre-permitting safety review must be regarded as preliminary and inconclusive. For example, the review conducted for the FPC for the National Bureau of Standards was only a preliminary step; many critical issues were not and could not be addressed because of the preliminary status of engineering work. Other problem areas were identified but, based on information and belief, responses were left open-ended. It has not been adequately established that safety monitoring in the post-permitting phase, from final design through construction and operation, will be adequately provided for. The recently enacted California Coastal Act (California Public Resources Code, Section 30000, et seq.) will require positive findings that any LNG facility proposed for siting in a populated area is consistent with public safety. The California Coastal Commission intends to exercise this responsibility.

(6) Additional studies are being conducted within California, regarding all three of the proposed sites for LNG regasification facilities. A preference for any site would be premature, until these studies are completed. For example, the City of Oxnard recently issued a Draft Environmental Impact Report (EIR) regarding Western Terminal's proposed facility at Oxnard. The first public hearing regarding the Draft EIR was held on November 4, 1976. A Final EIR for the project is required by the California Environmental Quality Act (California Public Resources Code, Section 21000, et seq.) prior to the issuance of any local or state permits. Also, from a public policy point of view, completion of the State EIR process appears indispensable to a decision as to the acceptability of Oxnard as a site for a LNG regasification facility.

At this point, it should be noted that in preparing its Draft EIR, the City of Oxnard had an independent safety study performed. It refused to rely on the

SAI risk assessment study to establish the safety of the proposed facility at Oxnard. Based on information and belief, a Final EIR for the Oxnard facility will be certified in March or April, 1977. The Final EIR for the Oxnard facilities will be submitted to the FPC as soon as it has been certified.

The preparation of an EIR for the proposed Point Conception site has recently begun. The reason for the delay has been Western Terminal's failure to file the necessary applications with the County of Santa Barbara until just recently. As stated above, with respect to the Oxnard EIR, completion of the State EIR process is indispensable to a decision regarding the acceptability of Point Conception as a site for a LNG regasification facility.

By order dated May 19, 1976, the Federal Power Commission denied petitions by the CPUC and the County of Santa Barbara for local hearings regarding the proposed LNG facilities at Los Angeles Harbor, Oxnard and Point Conception. At the same time, it has granted requests for local hearings at other sites in the lower 48 states, e.g., Everett, Massachusetts. After the Commission has denied the requests of state and local agencies for local hearings in California, it would be premature for California to endorse any site until the various State EIR processes have been completed. After the Oxnard and Point Conception EIRs have been subject to local public hearings and local exposure, there will be a better indication as to which site, if any is more acceptable for a LNG facility. Also, until the Oxnard and Point Conception EIRs have had such local exposure, it seems premature to argue, as the CPUC did, that the possibility of injunctive action is more likely at Point Conception than at the other for proposed locations.

The issue of seismic safety is presently under detailed technical review by the California Seismic Safety Commission (Seismic Safety Commission). The Seismic Safety Commission expects to issue an official report regarding each of three proposed sites by the end of 1976.[1] Design data presented to this Commission in the *El Paso/Alaska, Pacific Indonesia* and *Pacific Alaska* proceedings has been preliminary in many respects. For example, important studies relating to the design of the trestle at Oxnard were only completed in September 1976. These studies have not been submitted for the record in either the *El Paso/Alaska* or *Pacific Indonesia* proceedings. Until the Seismic Safety Commission has completed its study as to the proposed sites at Point Conception, Oxnard and Los Angeles Harbor, judgment as to the seismic issues should be reserved.

The Energy Commission is preparing a study relating to the issues of reliability of the proposed LNG regasification facilities. The study will be completed by the end of 1976 and will be available for presentation in the *Pacific Indonesia* and/or *Pacific Alaska proceedings.*

(7) The California Coastal Act includes a strong presumption in favor of remote siting, with the burden of proof on the applicant to establish safety. The above-described EIRs for Oxnard and Point Conception will be a vital element of state decision-making for all state permitting agencies, particularly the Coastal Commission and State Lands Commission, with respect to both safety and environmental issues. Since the County of Santa Barbara has not adopted the Commission staff's Final EIS in the *El Paso/Alaska* proceeding, it would be inappropriate to base a site preference on the Commission staff's environmental analysis which downgrades Point Conception.

Based on the foregoing, the Energy Commission submits that if this Commission (Federal Power Commission) recommends approval of the El Paso/Alaska project, it should approve siting of the El Paso/Alaska project at a remote site consistent with the California Coastal Act and the California Environmental Quality Act. The proposed sites at Los Angeles Harbor and Oxnard are not remote. Point Conception or some other remote site, or or offshore, should be approved by the FPC subject to the condition that a permit be obtained from the California Coastal Commission. The Federal Power Commission should take cognizance of the California Resources Agency's concerns on the environmental issues at each of the proposed sites.

[1] It should be noted that the U.S. Navy, acting through its Naval Facilities Engineering Command, has actively participated in technical discussions relating to seismic issues with respect to both the Los Angeles Harbor and Oxnard sites. Based on information and belief, the Navy has intervened in the *Pacific Indonesia* and *Pacific Alaska* proceedings because of the proximity of major naval facilities to both Oxnard and Los Angeles Harbor. In its recent comments on the Draft EIS for the *Pacific Alaska* project, the Navy agreed with the Commission Staff's conclusion that "the LNG terminal facilities should not be constructed at the proposed Los Angeles site in view of the seismic problem, the shipping congestion in Los Angeles Harbor and the resulting threat to a highly populated area.

If the El Paso/Alaska project is not certificated, the Energy Commission would recommend siting a facility at Point Conception or some other remote location (either onshore or offshore) for both the Pacific Alaska and Pacific Indonesia projects, until the unanswered safety questions are resolved by the appropriate California agency. These recommendations are without prejudice to the possible siting of a facility at Oxnard, depending on the development of the record on the *Pacific Indonesia* proceeding.

JOINT STATEMENT BY TOM QUINN, SPECIAL ASSISTANT TO THE GOVERNOR OF CALIFORNIA, AND CHAIRMAN, CALIFORNIA AIR RESOURCES BOARD, AND ROBERT BATINOVICH, PRESIDENT, CALIFORNIA PUBLIC UTILITIES COMMISSION

After extensive review of the proposed Sohio-BP oil tanker terminal, the state of California has concluded that the project, without proper federal controls, would seriously aggravate air pollution in the Los Angeles area and dangerously reduce our ability to receive natural gas. We therefore believe the project should be built only if it would serve the national interest and at the same time provide reasonable environmental safeguards for the state.

Recent discussions with the White House and Federal Energy Administration have convinced us that the national Administration would like to see the Sohio-BP terminal constructed if the environmental and natural gas problems can be resolved. As a result, we are prepared to grant the necessary permits, provided that certain specific conditions can be met.

The amount of air pollution potential from the project is staggering. A recent Air Resources Board staff report indicates that the project, without enforceable anti-pollution controls, would emit 22,300 pounds per day of sulfur dioxide, 7,800 pounds of nitrogen oxides, 1,100 pounds of particulate matter and 80,740 pounds of hydrocarbons. The hydrocarbons alone are equivalent to the exhaust emissions of 2.7 million new cars meeting California standards.

These emissions can be substantially reduced, but only if the federal government is willing to assist the state in promulgating stringent petroleum tanker operational conditions. With such conditions, coupled with effective enforcement, the terminal and tankers would emit 9,400 pounds per day of sulfur dioxide, 7,800 pounds of nitrogen oxides, 1,100 pounds of particulate matter and 1,140 pounds of hydrocarbons. In this case, the hydrocarbons are equivalent to the exhaust emissions of only 38,200 new cars.

Although the Los Angeles region is a non-attainment area as defined in the federal Clean Air Act, the Act now provides a "trade-off" or "off-set" policy which would allow the Sohio project to be constructed as long as the company reduces pollution from existing sources in order to provide a net overall reduction in pollution.

In an effort to resolve the air quality issues surrounding the Sohio-BP project, the state has been working closely with the company, the Port of Long Beach and various federal agencies. We have all discovered that the problems are substantial, involving pollution from petroleum tankers, on-shore storage tanks and other sources, and also involving the complex issue of tanker regulation.

During the past week, our discussions have been particularly productive and we are making progress toward resolving the outstanding questions. All parties are now in fairly close agreement concerning the amount of emissions from various phases of the project and we have developed some approaches to pollution mitigation which look promising. Sohio is cooperating with the state and we are hopeful that our current discussions will bring us to a speedy and proper decision.

The issue of natural gas supply is one, unfortunately, that may not be entirely under the control of Sohio-BP. Recent analyses by the California Public Utilities Commission and the state's Energy Commission indicate that the project could jeopardize California's natural gas delivery system and limit our ability to receive gas which would otherwise be available. This would occur because the Sohio-BP project involves the abandonment of a pipeline which now brings natural gas to our state. Under the Sohio plan, the line would be converted from a natural gas to a petroleum pipeline and the direction of its flow reversed. The loss of this gas pipeline capacity could limit our ability to receive new natural gas supplies.

We see two possible solutions to the gas supply problem. First, and most obviously, Sohio-BP could construct a new oil pipeline and allow the present gas line to remain in service. Second, Alaskan gas could be shipped directly to

California rather than by displacement. Direct delivery of the Alaskan gas would free up some capacity in our existing delivery system and allow us to abandon the use of one pipeline for the Sohio project. However, if we must receive our share of Alaskan gas by displacement, we will probably need the use of that line and we would be forced to curtail deliveries if the line were abandoned.

In summary, then, California is prepared to issue the necessary permits for the Sohio-BP project provided that:

(1) Our natural gas delivery system is protected, either by construction of a new oil pipeline by Sohio or by an immediate federal decision to deliver Alaskan gas directly to California.

(2) Appropriate federal agencies, in cooperation with the state, adopt legally enforceable tanker controls to prohibit purging, gas freeing, venting and ballasting into cargo tanks while in the greater Los Angeles air shed.

(3) Sohio-BP works cooperatively with state and local agencies to develop a legally acceptable set of emission "trade-offs".

If these conditions can be met, and if the national interest indicates that Long Beach is the preferred location for an Alaskan oil supertanker terminal, California is prepared and willing to speedily issue the necessary state permits.

The CHAIRMAN. Several years ago Louisiana was not cooperating with the Federal Government. The Governor of Louisiana became absolutely outraged. Louisiana was drilling out in the gulf, doing everything they could do to proceed. The Federal Government was not doing anything but impeding production, such as requiring nine permits to let leases and to drill in the Gulf of Mexico and to do all of the things that are needed to produce offshore.

When they called upon the Governor to cut back to a 55 mph speed limit, he issued a response about as polite as it could be and as insulting as he intended for it to be, that he did not intend to comply. Then the Federal Government said that if he did not cooperate on lowering the speed limit, Louisiana would not receive its highway money. Faced with that alternative, the Governor had no choice but to comply with the 55 mph speed limit.

That carrot and stick approach has been used for Louisiana. People of other States are not cooperating in solving the problem. Why can not the rest of you take the same view?

It seems to me we all ought to be willing to cooperate in solving these problems. Who does not cooperate—speaking as chairman of the tax writing committee—ought to pay a lot of taxes, a backbreaking amount of taxes, until they see the light. We want to cooperate with California, but we would like California to cooperate with us. I wish you would pass that along to Chairman Maullin.

To us, cooperation is essential.

Mr. BROWN. I will indeed.

The CHAIRMAN. Cooperation is a two-way street.

Senator Packwood?

Senator PACKWOOD. I have no questions.

The CHAIRMAN. Senator Roth?

Senator ROTH. I have no questions.

The CHAIRMAN. Thank you very much.

Mr. BROWN. Thank you, Mr. Chairman.

The CHAIRMAN. Next, we will call a panel, consisting of Mr. Howard Larson, vice president, environmental affairs of Outboard Marine Corp. and Mr. George Page, chairman of Teleflex, Inc.

We are very pleased to have you, gentlemen.

STATEMENT OF GEORGE PAGE, CHAIRMAN, TELEFLEX, INC.

Mr. PAGE. Mr. Chairman, my name is George Page of Teleflex, Inc. I am accompanied here today by Mr. Howard Larson, vice president for environmental affairs of Outboard Marine Corp.

We are presenting testimony on behalf of the Boating Industry Association of Chicago, Ill. and the National Association of Engine and Boat Manufacturers.

Our associations and industry have long recognized the need to conserve energy—particularly petroleum-based fuels. In the last 5 years, we have developed new construction techniques both increasing engine efficiency and permitting lighter boats which require less power to move. In addition, work continues on development of even more efficient engines and on the possible use of cheaper or more plentiful fuels than gasoline.

More specifically, the boating industry and boating public recognize their obligations to do their part for energy conservation. The financial incentive to save fuel provided by elimination of the refundable portion of the Federal fuel tax as contemplated in section 1231 of S. 1472 thus is appropriate.

It should be understood, however, that sacrifices by the boating industry and public result in very limited energy conservation. Boating uses the equivalent of less than one-half a tank of gas per car in a whole year. Thus, the amount of savings to be achieved by boating under any circumstances is small. In addition, most of the burden of any legislation affecting boating will fall primarily on middle income families not on the affluent.

It should also be noted that the boating industry is highly labor intensive. There are approximately 350,000 persons directly employed on a full-time basis and an additional 150,000 part-time employees in the recreational marine industry. In addition, boating-related activities associated with sport fishing, tourism and resorts bring the total number of persons relying on recreational boating for employment to at least 1 million. It is not difficult to see that an unfair or severe burden on our industry or its customers could result in a substantial increase in unmployment.

We would further suggest that funds available as the result of elimination of the current rebate of half of the Federal excise tax on fuel for motorboats should not merely be allocated to the Bureau of Outdoor Recreation general fund as contemplated in section 1231 of S. 1472. We recognize that this committee does not have jurisdiction to amend the Land and Water Conservation Fund Act.

Nevertheless, because our suggestion for use of these funds would appear to reduce fuel consumption and results from the change in the tax law contemplated by section 1231 we believe it appropriate for this committee to address the problem which we are raising in report language.

In 1964, when the Land and Water Conservation Fund Act was passed by the Congress, the support of the recreational boatmen was gained by the promise that tax proceeds allocated to this fund would be used to build boating facilities along with other outdoor recreational development. During the first decade of the fund's existence, between 25 percent and 33 percent of the fund's revenues came from the Federal marine fuel tax. Yet, the amount returned to boatmen in fulfillment of this promise has been minimal. In contrast to this, many States allocated the receipts from the State marine fuel tax specifically to boating facilities.

There have been cases where water impoundments have been developed or improved using Federal marine fuel taxes from the BOR fund directly or through BOR grants to the States where motorboating—which helped pay for the project in the first place—is banned.

Power boatmen have contributed $300 million in Federal motorboat fuel taxes to the fund and are the only specifically identifiable contributing group. Although the fund has disbursed $305 million for "water access" projects, even the most cursory examination shows that the disbursements for these projects far overstate the recreational benefits which the fund has returned to power boatmen. For example, a fund grant of approximately $2 million has been made for the development of Lums Pond State Park in Delaware. Of this $2 million, less than $50,000 was used for a boat lift and boat ramp. There are other examples to be cited, all of which clearly indicate that a small fraction of the $300 million paid by boatmen in Federal fuel tax is being returned by the BOR in the form of boating facilities.

We suggest that elimination of the refundable amount of this tax should not perpetrate this inequity. Rather, any one of several alternatives for use of the funds no longer refundable should be adopted. We would suggest that the funds be directed specifically for use in the development of boating facilities near where people are. Over 75 percent of the U.S. population lives in major metropolitan areas where boating facilities are badly needed to the extent that these areas are located on water. Besides the obvious benefits of jobs, attractive redevelopment from urban decay, and providing recreational opportunities where the people are, energy can be saved by reducing the need to travel distances to rural recreation. Under such circumstances, boatmen will feel that their sacrifice of the 2 cents per gallon refundable amount of the Federal marine fuel tax will be worth it.

In summary, elimination of the presently refundable 2 cents per gallon Federal gasoline tax will cost boatmen about $15 million a year. The boating industry is not opposing this cost increase because it accepts the administration's premise that this increased cost may provide an incentive for fuel conservation. Specific allocation of these funds toward the development of boating facilities where the people are will take the edge off the special sacrifice boatmen are making and also will reduce highway use of fuel traveling to boating facilities outside the urban areas.

Thank you, Mr. Chairman. Mr. Larson will now make his statement.

STATEMENT OF HOWARD LARSON, VICE PRESIDENT, ENVIRONMENTAL AFFAIRS OF OUTBOARD MARINE CORP.

Mr. LARSON. Thank you, Mr. Chairman. My testimony is directed solely to a provision included by the Ad Hoc Committee on Energy to H.R. 8444.

Section 385 of H.R. 8444 directs the Secretary of Transportation to complete a study "of the energy conservation potential of recreational motor vehicles including, but not limited to, aircraft and motorboats which are designed for recreational use." This study is to contain recommendations concerning the desirability and practicability of fuel efficiency standards or fuel taxes on such vehicles.

We are bringing this matter to the committee's attention because the proposed study does direct the consideration of fuel taxes on recreational boats, a matter within this committee's jurisdiction, and because no hearings have been held on this issue before any committee of the Congress.

Section 385 was added to H.R. 8444 by the Ad Hoc Energy Committee without hearings. It had not been considered by any of the standing committees of the House. In addition, since the Senate Energy and Natural Resources Committee has completed its hearings, no forum is presented in the Senate other than in this committee where we may raise this issue.

The provision calling for the study of off-road recreational vehicles was retained on the House floor by the narrowest of margins, a 212 to 210 vote in favor of the provision. Since the Senate Energy and Natural Resources Committee has completed work on the corresponding title to the Senate bill, it is possible that the issue will be considered on the Senate floor. We urge that this study not be included in S. 1469 and S. 1472 when they are considered by the full Senate and that this committee seek to delete section 385 of H.R. 8444 when the matter reaches conference later this year.

To summarize our position, we believe an off-road vehicle study to be discriminatory, unnecessary, and a waste of the taxpayers' money.

The recreational boating industry readily concedes that recreation must bear a share of any conservation burden imposed on our Nation. This is the reason that the boating industry reluctantly has supported section 1231 of S. 1472. Having made this concession, we feel that the proposed study seeks to assure that further discriminatory burdens will be imposed on the industry. The tenor of the legislative language is virtually a directive to the Department of Transportation to recommend some action against the industry.

Not only is this study limited to the recreational industry as opposed to other similar industries, but certain segments of that industry are singled out for study. A Booz, Allen & Hamilton study prepared for the Federal Energy Office in 1974 listed 10 separate categories of leisure/recreational activities. Yet the study mandated by H.R. 8444 would single out only several subcategories within these 10 categories for study by the Department of Transportation.

In addition to its discriminatory nature, section 385 is unnecessary. The recreational boating industry has a significant incentive at the present time to increase the efficiency of its engines. The industry has a long-term commitment to, and a highly commendable record in, achieving greater efficiency for its engines. The engine manufacturers have expended considerable sums of money during the past 15 years to achieve improvements in energy efficiency.

As with automotive engines, those powerplants designed for marine use have achieved a rather high degree of sophistication. Improvements have resulted from many individual contributions rather than any single innovation.

Following are some of the developments which have contributed to the efficient modern engine:

Tuned exhaust system and loop scavenging through hub exhaust.

Higher engine compression and better intake and exhaust porting.

Pressure backed piston rings for reduced friction.

Antifriction bearings and reduced fuel/oil ratio.

Improved induction system and elimination of crankcase drains.

More precise carburetor calibration.

Improved combustion chamber design.

Capacitor discharge ignition with tailored spark and throttle advance (less misfires).

Thermostatically controlled cooling systems.

Hydrodynamically designed lower units and propellers.

The boating industry understands that greater fuel efficiency is demanded by the consumer at the present time and already is working as rigorously as possible to increase this efficiency as a matter of economic survival. No inducement from the Federal level is necessary.

If the off-road vehicle study is merely designed to determine the desirability of fuel efficiency standards for motorboats, such statutory authority would appear to be unnecessary. The Energy Policy and Conservation Act of 1975 gives the Federal Energy Administration authority to establish such standards for consumer products. The definition of such products in the act would appear to be sufficiently broad to cover recreational boats. In addition, section 801 of the newly enacted Department of Energy Organization Act directs the new department to develop comprehensive strategies and proposals concerning all forms of energy utilization. The DOE thus has ample statutory to act without the need for section 385. A separate Department of Transportation study will result merely in a duplication of effort.

If the study is designed to evaluate the effects of a fuel tax on motorboats, DOT does not appear to be the appropriate agency to undertake such a study. In addition, the Ways and Means Committee recently reported out H.R. 8309 which imposes a fuel tax on inland waterway users (as opposed to the user fee approach adopted by the Senate in S. 1529). Title III of H.R. 8309 directs DOT and the Department of Commerce to carry out a study regarding the appropriateness of fuel taxes on all inland waterway users. The study mandated by section 385 imposes an additional burden and expense on both the Federal agencies and the industries involved.

Numerous studies already exist concerning restrictions designed to limit substantially motorboat fuel consumption, including a 300-page Federal Energy Administration investigation of the economic and environmental implications of weekend driving limitations.

A study similar to the one contemplated by section 385 already has been made by the Department of Transportation at its Transportation System Center in Cambridge, Mass. The study is summarized in Rep. No. DOT-TSC-OST-73-14.

Among the findings in this report are the following facts: "The modes of transportation and different vehicles within the modes use quite different amounts of energy to accomplish the transportation purpose." The report found that the typical automobile provides 30 passenger miles per gallon (pm/g), the airplane 16 pm/g, and pleasure boats 22 pm/g. These boats, according to the report, carry a mean of 3.6 passengers as they are used for family recreation. Pleasure boats thus are an extremely efficient manner of providing recreational enjoyment to a large number of people.

The debate on the House floor indicated a feeling that the boatowner is affluent and can well afford to pay a punitive tax. This is completely contrary to a Department of Transportation study by the Coast Guard which found that 87 percent of boating households earn less than $15,000 annually. Only 2 percent earn more than $25,000 annually. The average owner age is 34.2 years and this is the middle income worker who bears the heaviest burden of taxation.

The underlying factual conclusions upon which the study mandated by section 385 is based are readily available and need no further study: The recreational boating industry is extremely labor intensive and is composed of a very large number of separate companies, over 2,500 manufacturers of marine products (excluding accessories) and 16,500 retail dealers and distributors. Recreational boating uses less than one-half of 1 percent of all gasoline consumed in the United States annually, but it generates some $5 billion in retail sales.

Accordingly, fuel conservation policies that would cause a decrease in boating equipment sales would save very little fuel but will result in significant unemployment, add to recessionary pressures, and have a detrimental effect on our U.S. balance of trade (marine exports are currently $140 million annually). A costly study to confirm these facts, estimated during the floor debate in the House at as much as $1 million, is simply not necessary.

In conclusion, we appreciate the opportunity to express our concern about the proposed off-road vehicle study and urge the committee to insure that this study is not a part of the national energy legislation.

The CHAIRMAN. Thank you very much, gentlemen.

Any questions, Senator Roth?

Senator ROTH. No questions.

The CHAIRMAN. We will certainly study this material. You know, you raise a matter that is in not the bill that is before our committee, but I understand your problem.

Thank you very much.

[The prepared statement of Mr. Page and Mr. Larson follows:]

STATEMENTS OF GEORGE PAGE AND HOWARD LARSON ON BEHALF OF THE BOATING INDUSTRY ASSOCIATIONS AND THE NATIONAL ASSOCIATION OF ENGINE AND BOAT MANUFACTURERS

SUMMARY

1. Section 1231 of S. 1472 eliminates a two cent per gallon rebate now permitted with respect to the motorboat fuel tax and directs that these proceeds be allocated to the Land and Water Conservation Fund.

2. The recreational boating industry does not oppose this provision. It does urge, however, that the proceeds be utilized to develop boating-related facilities near metropolitan areas because of the energy conservation and rehabilitation benefits from such projects.

3. Section 385 of the House-passed energy bill, H.R. 8444, provides for a study by the Department of Transportation of the energy conservation potential of recreational motor vehicles.

(*a*) This proposal is discriminatory because it is aimed at the recreational industry and singles out several segments within that industry.

(*b*) The study is unnecessary for a number of reasons:

(i) The recreational boating industry already has sufficient economic incentive to increase fuel efficiency of recreational boat motors.

(ii) The Department of Energy has sufficient authority under both the Energy Policy and Conservation Act and the Department of Energy Organization Act to do everything mandated by § 385. A Department of Transportation study would be a duplication of effort.

(iii) Numerous studies already exist concerning restrictions designed to limit substantially motorboat fuel consumption and concerning motorboat engine fuel efficiency.

(*c*) The potential for fuel conservation by the boating industry is small because of the limited amount of fuel consumed (one-half of one percent of all gasoline consumed in the U.S. annually). Thus an expensive study is not justified from a cost-benefit viewpoint.

STATEMENT

This testimony and the accompanying statement of Mr. Howard Larson are presented on behalf of the Boating Industry Associations (BIA) of Chicago, Illinois and the National Association of Engine and Boat Manufacturers (NAEBM) of New York City, New York. Together, the two associations have as members more than 800 boat builders, engine and motor manufacturers, boat trailer manufacturers, accessory producers and firms servicing the recreational marine industry. The associations also work with affiliated groups representing marine distributors, dealers, boat owners and others involved in recreational boating.

Our associations and our industry have long recognized the need to conserve energy—particularly petroleum-based fuels. In the last five years, we have developed new construction techniques both increasing engine efficiency and permitting lighter boats which require less power to move. In addition, work continues on development of even more efficient engines and on the possible use of cheaper or more plentiful fuels than gasoline.

More specifically, the boating industry and boating public recognize their obligations to do their part for energy conservation. The financial incentive to save fuel provided by elimination of the refundable portion of the federal fuel tax as contemplated in § 1231 of S. 1472 thus is appropriate.

It should be understood, however, that sacrifices by the boating industry and public result in very limited energy conservation. Boating uses the equivalent of less than one-half of a tank of gas per car in a whole year. Thus, the amount of savings to be achieved by boating under any circumstances is small. In addition, most of the burden of any legislation affecting boating will fall primarily on middle income families, not on the affluent.

It should also be noted that the boating industry is highly labor intensive. There are approximately 350,000 persons directly employed on a full-time basis and an additional 150,000 part-time employees in the recreational marine industry. In addition, boating-related activities associated with sport fishing, tourism and resorts bring the total number of persons relying on recreational boating for employment to at least one million. It is not difficult to see that an unfair or severe burden on our industry or its customers could result in a substantial increase in unemployment.

We would further suggest that funds available as the result of elimination of the current rebate of half of the federal excise tax on fuel for motor boats should not merely be allocated to the Bureau of Outdoor Recreational general fund as contemplated in § 1231 of S. 1472. We recognize that this Committee does not have jurisdiction to amend the Land and Water Conservation Fund Act. Nevertheless, because our suggestion for use of these funds would appear to reduce fuel consumption and results from the change in the tax law contemplated by § 1231, we believe it appropriate for this Committee to address the problem which we are raising in report language.

In 1964, when the Land and Water Conservation Fund Act was passed by the Congress, the support of recreational boatmen was gained by the promise that tax proceeds allocated to this Fund would be used to build boating facilities along with other outdoor recreational development. During the first decade of the Fund's existence, between 25 percent and 33 percent of the Fund's revenues came from the federal marine fuel tax. Yet, the amount returned to boatmen in fulfillment of this promise has been minimal. In contrast to this, many states allocate the receipts from the state marine fuel tax specifically to boating facilities.

There have been cases where water impoundments have been developed or improved using federal marine fuel taxes from the BOR fund directly or through BOR grants to the states where motor boating which helped pay for the project in the first place is banned. Power boatmen have contributed $300 million in federal motorboat fuel taxes to the fund and are the only specifically identifiable contributing group. Although the fund has disbursed $305 million for "water access" projects, even the most cursory examination shows that the disbursements for these projects far overstate the recreational benefits which the fund has returned to power boatmen. For example, a fund grant of approximately $2 million has been made for the development of Lums Pond State Park in Delaware. Of this $2 million, less than $50,000 was used for a boat lift and boat ramp. There are other examples to be cited, all of which clearly indicate that a small fraction of the $300 million paid by boatmen in federal fuel tax is being returned by the BOR in the form of boating facilities.

We suggest that elimination of the refundable amount of this tax should not perpetuate this inequity. Rather, any one of several alternatives for use of the funds no longer refundable should be adopted. We would suggest that the funds be directed specifically for use in the development of boating facilities near where people are. Over 75 percent of the U.S. population lives in major metropolitan areas where boating facilities are badly needed to the extent that these areas are located on water. Besides the obvious benefits of jobs, attractive redevelopment from urban decay, and providing recreational opportunities where the people are, energy can be saved by reducing the need to travel distances to rural recreation. Under such circumstances, boatmen will feel that their sacrifice of the 2-cents-per-gallon refundable amount of the federal marine fuel tax will be worth it.

In summary, elimination of the presently refundable 2-cents-per-gallon federal gasoline tax will cost boatmen about $15 million a year. The boating industry is not opposing this cost increase because it accepts the Administration's premise that this increased cost may provide an incentive for fuel conservation. Specific allocation of these Funds toward the development of boating facilities where the people are will take the edge off the special sacrifice boatmen are making and also will reduce highway use of fuel traveling to boating facilities outside the urban areas.

For the Committee's further information we have attached informational data for the record about our industry, its customers and its fuel consumption.

ATTACHMENT

BOATING IS AN INDUSTRY—AS WELL AS AMERICA'S FAVORITE FAMILY SPORT

We want you to know about our industry—the boating industry.

We employ 350,000 full-time people in the manufacture, selling and servicing of all types of boating recreational products.

We contribute over $5 billion annually to the gross national product and several hundred million dollars of net exports toward a favorable balance of trade.

Our products are purchased and enjoyed across the entire spectrum of income and occupational groups.

Our products are manufactured in every state of the union.

We are a diverse industry ranging from publicly held manufacturers to the thousands of small companies which predominate at the manufacturing and retail level.

We want you to know a little more about our industry—our strengths and our problems—and our future.

THE RECREATIONAL BOATMAN

Seven million power boating families and 3 million non-powered boating families, mainly blue and white collar workers, get primary recreation from a boat which averages under 16 feet in length and uses little fuel for fishing, hunting and short-range Sunday boating over much shorter distances than the customary family Sunday joy-ride in an automobile. Contrary to a popular belief, the "yachtsman" with his large inboard cruiser is not in any way representative of the average boatman.

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Boating is a "middle America" recreation involving more than 10 million owner-families, more than 8 million of whom own boats with gasoline-powered motors or engines. Contrary to stereotyped beliefs about the high affluence and large craft involved in boating, the facts indicate the broad scope and moderate means of this enormously popular way of life:

Small boats account for virtually all of recreational boating with unpowered, outboard and inboard/outboard powered type boats outnumbering the larger inboard types by more than 75 to 1 (1976 sales figures). There are less than 75,000 boats over 40 feet long in the entire U.S.

Skilled, semi-skilled, clerical, proprietor and service workers greatly outnumber professionals in power boat ownership by a margin of 4 to 1.

Most boat owners have an annual income of $15,000 or less.

The average length of power boats—and all boats—purchased in 1976 was less than 16 feet.

Fuel consumption by the majority of boat users is small. A 1975 Coast Guard study showed the average boatman spent 47 per cent of his time fishing, a very low consumption use.

The average outboard motor sold in 1976 was under 42 horsepower, and 39 per cent of all motors purchased were less than 20 horsepower.

The great majority of outboard motor fuel tanks are portable tanks holding 6 gallons of fuel and only the few large cruising craft utilize built-in tanks.

Non-power boats (sailboats, canoes, fishing boats) number 3 million.

OCCUPATIONS OF PURCHASERS OF RECREATIONAL BOATING PRODUCTS IN 1976

	Motors (Percent employed buyers)	Outboard boats (Percent employed buyers)	(Percent employed population)
Skilled workers	20.6	21.2	12.2
Semiskilled workers	11.1	11.6	15.8
Service workers	9.1	9.4	15.5
Factory labor	1.6	1.6	6.0
Clerical, sales	20.6	20.6	23.8
Farmers, farm labor	3.5	3.3	4.3
Professional	17.8	16.4	13.5
Managers, proprietors	15.7	15.9	8.9
Total	100.0	100.0	100.0

Note: This table covers only employed workers to allow for better comparison with census figures. However, retired persons are the 3d largest group of purchasers when total population is considered. In 1976, 19.4 percent of all motors were purchased by retired persons (primarily) and 14.9 percent of the boats.

Source: Marex, Inc.

HOW MUCH FUEL DOES THE U.S. RECREATIONAL BOATING FLEET CONSUME?

Recreational boats burn about 900 million gallons of fuel annually—less than one-half of one per cent of the nation's total petroleum consumption. This amount is equal to less than a half a tank of gasoline per year for each automobile in the U.S.

The total amount of fuel consumed by U.S. boatmen has been the subject of study for a number of years. The reason for such studies is that a portion of federal fuel taxes is earmarked each year for the acquisition, development and maintenance of outdoor recreational facilities. In determining what percentage of taxes come from fuel used in recreational boats, the U.S. Bureau of Public Roads has developed data on the subject. In addition, some 30 states also earmark a portion of their state fuel tax revenues for recreational purposes and a number of these states have made intensive studies to determine what portion of their fuel taxes come from boating.

Finally, industry statistics provide useful information on the number of power boats in use on all U.S. waters, the average horsepower of marine engines, the amount of fuel they consume per hour and the average number of hours they are actually operated.

On the basis of data from these sources, it is estimated that recreational boats consume approximately 900 million gallons of fuel annually, less than one-half of one per cent of the total amount of petroleum used in the U.S. annually.

Put another way, if all recreational boating were discontinued, the amount of fuel "saved" would be equivalent to less than one-half tank of gas per year for every automobile in the U.S. The adverse economic "ripple effect" of wiping out the marine industry and reducing dependent and/or related economic activity could cause a one-half percent increase in national unemployment. In many areas, when a marine manufacturer is the major employer of water-associated recreation and tourism are major industries this figure would be substantially higher.

The CHAIRMAN. Next, we will call Mr. John L. Baker, president, Aircraft Owners and Pilots Association.

Mr. Baker?

STATEMENT OF JOHN L. BAKER, PRESIDENT, AIRCRAFT OWNERS AND PILOTS ASSOCIATION

Mr. BAKER. The Aircraft Owners and Pilots Association represents 205,000 aircraft owners and operators in the noncommercial aviation, or general aviation, as it is more properly known. Before I make the limited number of comments that I have, I would like to place general aviation in perspective, since it is often quite misunderstood. It is not recreational aviation.

Less than 5 percent of the general aviation activity is recreational. It constitutes 98 percent of the Nation's civil aircraft, 96 percent of the pilots, 85 percent of the hours flown in the country, roughly 34 million flight-hours a year versus 6 million that the airlines fly, and it carries one out of every three intercity passengers in the United States by air.

It serves 13,000 airports, as opposed to 450 served by the airlines, and again, for contrast, 96 percent of the airlines passengers emanate from 151 airports. So general aviation really is, if not the arteries, at least the capillaries of the air transportation system.

I think the salient point is, although we carry 100 million passengers by air every year intercity compared to the airlines' 200 million, we do it on 6 percent of the fuel consumed, and roughly six-tenths of 1 percent of the total transportation fuel.

If the statements sound somewhat defensive, it is, because we are a little paranoid. Regularly, each time there is a national problem of some sort, general aviation is lumped in with recreational uses of fuel and we are put to the burden of defending our existence on a regular basis.

Regarding the administration's energy proposals, our basic observation is that it results in higher taxes, higher energy costs and very little incentive for increased supplies. We believe it is incumbent upon Congress to insure that we have a plan that stimulates oil and gas exploration and production, expands energy alternatives, provides incentives for conversion to alternative fuels for nonmobile users, since all transportation modes are basically tied to petroleum based fuels, and obviously to minimize as much as possible any cost increases coming from the current difficulties.

We urge the committee, and the Senate, to reject the 4-cent additional fuel tax on general aviation which is sought by the administration. GAO, Ways and Means, and Secretary Adams, when he testified in the House, conceded that the tax on noncommercial aviation would result in no measurable fuel savings but would cost general aviation in general $38 million the first year, $76 million by 1985, and this burden would be thrown on the highest taxed area of transportation.

General aviation pays more fuel tax than anybody else in the transportation business.

By the way, general aviation also includes the commuter air carrier, which, I understand, in Senator Roth's State is the only air service he has.

While not enthusiastic about the crude oil tax, we recognize that there are burdens that should be shared across the entire population, but we believe that they should not be used for income redistribution but rather should be used for research, development and incentives for additional production and regarding a related subject, I would hope that we would be back here soon, testifying before the committee to gain a reduction in the total fuel tax we are paying to the airport/airways trust fund, because the administration has not spent the money as Congress mandated.

We now have a $3.2 billion surplus in that fund. I think the burden should be cut back.

In summary, we urge the committee to promote a climate in which oil and other energy producers can meet the Nation's needs.

I summarize our position. We do want to emphasize to the committee that we believe we have a contribution to make and we do not believe we should be discriminated against as we have been in the past in the energy field.

The CHAIRMAN. Thank you very much, Mr. Baker, for a good statement.

Senator Matsunaga?

Senator MATSUNAGA. No questions.

The CHAIRMAN. Thank you very much.

[The prepared statement of Mr. Baker follows:]

STATEMENT OF JOHN L. BAKER, PRESIDENT, AIRCRAFT OWNERS AND PILOTS ASSOCIATION (AOPA)

Mr. Chairman and Members of the Committee: I am John Baker, President of Aircraft Owners and Pilots Association. I appreciate this opportunity to present AOPA's views respecting the energy tax proposals before you. AOPA—with more than 200,000 active members—is the principal organization of those who use general aviation aircraft. While essentially we represent ultimate consumers, I believe our airman's perspective is somewhat broader than that interest alone.

Fuel is the most essential thing to continued operation of our aircraft. Indeed, without fuel, our aircraft are useless—and so is our investment in them. Continued operation of our aircraft is important to the nation's economy and to the achievement of many of its social and environmental goals.

General aviation accounts for 98 percent of the nation's civil aircraft and 96 percent of its civil pilots.

General aviation flies more than 85 percent of the hours flown by all civil aircraft and covers 62 percent of the aircraft miles. It flies 34 million hours annually compared to six million for the certificated airlines. It covers 4.2 billion miles a year while the airlines travel 2.6 billion.

General aviation carries one-third of the people in intercity air transportation—about 100 million last year. (Source: FAA Study)

General aviation includes every form of aeronautical activity except military and airline. It is essential to efficient agriculture, forestry, fishing, construction, power and pipeline operations, petroleum production, land management, mail service and a host of other things too numerous to name. It is involved in tourism, government administration, business management, education, news dissemination, sports, the performing arts, and on and on. It is also a form of recreation in itself, though this is greatly overshadowed in reality, if not in public perception, by its business applications.

General aviation serves those who do not directly use the airplane. It makes communities and rural areas around more than 13,000 airports accessible by air from all parts of the world. By contrast, airlines serve about 417 airports in the contiguous 48 states, 213 in Alaska (and most of these are actually more general aviation than airline in character) and eight in Hawaii. About 20 percent of the airline flights depart from just five points and about 96 percent of airline passengers are enplaned at 152 locations. General aviation fills the gap.

General aviation does all these things and more on a remarkably small amount of aviation fuel—less than 6 percent of the fuel consumed by all sectors of aviation—and a minuscule fraction of that consumed by transportation as a whole.

Energy and economics dictate that large airline aircraft cannot efficiently serve the people of medium and small communities or those in rural areas. People in these places must look to general aviation for satisfaction of their air service needs. As business decentralizes and metropolitan populations disperse, these lower population areas take on added significance in the nation's social and economic structure—and so does general aviation.

Environmental concerns, spiraling construction costs and land use considerations greatly reduce the likelihood of constructing new major airports. To fill the need, there must and will be many smaller, more convenient, less expensive, less noisy, general aviation airports.

Time is also a precious resource and a commodity which aviation conserves with great efficiency. General aviation airplanes make it possible to go more places and do business with more people in less time and at less cost than by any other means of transport. Inevitably, transportation in the future will be more and more by air . . . and air transportation will be more and more by general aviation.

With this background of general aviation involvement in the nation's social and economic intercourse, it is easy to understand our concern about adequate fuel supplies and adverse effects of excessive and discriminatory taxation.

Ultimately, all government expenditures are derived from personal income in one way or another. Expenditures by all levels of government now approximate 42 percent of total personal income. (In 1974 total personal income amounted to $1,153.3 billion and all government expenditures amounted to $480.1 billion. (Source: Statistical Abstract, 1976, p. 422, 638))

Resistance to additional taxation is mounting at an accelerating rate. The mail from our members reflects this and we have noted many of the difficulties experienced by all levels of government in trying to increase taxes or bonded debt for programs not related to aviation. We observe also the economy's "stagflation" and the inhibiting effects that various government programs, production and price controls have had on growth. We conclude that additional constraints will be counterproductive in the energy field and that taxation is at or past the point of diminishing returns.

We are reconciled to the fact that our fuel will cost more. As between the prospect of added cost or no fuel—we opt for more fuel. It may not be cheap—but it is essential to the functioning of our economy and the achievement of the social and economic goals of the nation.

While conservation is important (though by conservation we begin to suspect that most people mean conservation on the part of somebody else), conservation is only a stopgap—not a solution—to the energy problem. It is also worth noting that if general aviation fuel usage were eliminated completely—a course which we do not advocate, quite naturally—the amount of fuel saved, less than four-tenths of one percent (21.9 million barrels in 1975), would go unnoticed in the nation's total petroleum consumption of more than 6 million barrels a year. (Sources: Bureau of Mines Study; Statistical Abstract 1976)

We are distressed by the energy program recommended by the Administration. As we see it, fuel costs will go up as a result of taxes. The taxes will be used for rebates and income transfer payments. The taxes will not be used to increase domestic energy supplies, including those from oil upon which aviation is dependent. Consequently, we believe the proper remedy is to relieve the energy-producing companies from the governmental constraints of controls on production and pric so that it will again become economic for those enterprises to provide adequate supplies. In the end, either way, the price of fuel will go up—but the Administration's proposal would discourage increased production of energy whereas resorting to the market system would increase production.

We acknowledge that a complete energy program will cost money. But we think the energy problem is so vital that all other existing federal government programs should be reduced by something like 5 percent so that approximately $20 billion a year for so long as necessary would be generated for government energy program purposes. This money could assist those users who can convert to nonpetroleum energy supplies to do so. It could be employed for research and development of energy resource and supply alternatives. It could help finance establishment of a national oil reserve as a buffer in the event of another oil embargo by foreign suppliers.

We recognize the difficulties of gaining acceptance of the kind of switch in the use of presently available federal financial resources that we suggest. But those difficulties seem less than the consequences of public wrath at increased taxation, the ensuing inflation and diminishing oil supplies that would follow pursuit of the Administration's program.

We recommend that the proposed tax on auto and "noncommercial aviation" fuel be rejected—regardless of whether set at four, five or some other cents per gallon. Generally, we who fly must also drive to and from the airport; hence, we oppose the tax on auto fuel as well as aviation fuel. We applaud the House action rejecting this proposal and hope the Senate will not give it new life, which we are grateful to note from your comments to preceding witnesses, seems unlikely.

We also point out that the Administration proposes no similar energy tax on airlines, railroads or barges which all consume far greater amounts of fuel than does "noncommercial aviation." (Source: DOT Summary of National Transportation Statistics) The term, "noncommercial aviation," by the way, is a misnomer that induces some people to think this sector of aviation is less important than it is.

In a peripheral but related area, we recommend the existing excise tax of 7 cents per gallon on what is mistakenly called "noncommercial aviation" fuel be reduced to 4 cents per gallon as it was prior to 1970. This action is warranted for three reasons.

1. Noncommercial aviation is a very efficient user of fuel and consumers less than 6 percent of all aviation fuel. This is notable in view of all the activities and achievements of general aviation outlined previously. (For comparison, note that manufacturing consumes 0.7 percent, military 24.9 percent and airlines 68.5 percent of aviation fuel.) (Source: Bureau of Mines Mineral Industry Surveys)

2. The Airport and Airway Trust Fund balance for May 1977 was $3.2 billion. (Source: Treasury Report) The balance has increased steadily since unauthorized diversions were halted some years ago. Hence more revenue is being collected for airport and airway purposes than is required. Those purposes were the sole reason for increasing the tax. We think Trust Fund revenues should not exceed expenditures so greatly.

3. Proposals for the alleviation of airline aircraft noise have been advanced by various Members of Congress and the Administration. These proposals entail diversion of 25 percent of Airport and Airway Trust Fund revenues derived from passengers and shippers to financing of retrofit or replacement of airline aircraft. The reduction we propose would maintain the relative balance in the tax impact of airport and airway expenditures on the various sectors of aviation.

We oppose the crude oil equalization tax because of its general tax increase implications discussed previously. We recognize, however, that it is much less discriminatory and more broadly based than some of the other tax proposals. We think a crude oil tax will inhibit development of additional oil resources unless it is accompanied by substantial "plowback" provisions to encourage development. Even so, we believe that letting oil production respond to market forces will achieve this essential objective more swiftly and efficiently. We think the competitive forces will perform their usual role of moderating price advances if the market system is unleashed to do its job. We see this course of action as the only real hope of reducing the nation's dependence on oil imports.

Hence, it follows that we favor elimination of production and price controls on oil and gas as a means of assuring adequate fuel supplies. We think such a reduction is the simplest, swiftest, cheapest and most effective way to solve the supply problem. A continuation of these controls, in view of the historical evidence (of the consequences of price controls, production allocations, reduction of depletion allowances, pressures for vertical and horizontal divestiture, for example), is only likely to make the supply problem worse than it is now.

It also follows that we think the crude oil rebate proposals are illogical and have no place in an energy program. Income transfers of this kind yield no hope of solving the energy supply problem; they will only aggravate it.

The House took two lesser actions of dubious merit.

It voted to eliminate the deduction for state and local fuel taxes. While the impact of enactment of this idea would not be as crucial as some of the other tax proposals, it is symbolic of the insatiable appetite for increased taxes. We recommend that you reject it.

The House also voted for two studies of energy efficiency of recreational vehicles including aircraft and bicycles. We think both studies a waste of time and money and recommend they be scuttled.

To conclude: We urge you to provide the kind of economic climate in which oil and other energy producers can provide the fuel supplies that are essential to the nation's functioning and the fulfillment of the nation's people in all their various pursuits for personal satisfaction and achievement. Energy is essential and we must pay its price or do without. As Thomas Jefferson said of agriculture, "Were we directed from Washington when to sow and when to reap, we should soon want for bread." We now may rephrase it slightly: Having been directed from Washington where, when, how and at what price to drill and pump, we are now in want of oil! Please, set things right before it's too late.

The CHAIRMAN. Next, we will call Mr. David C. Crowley, executive vice president of the American Association of Homes for the Aging.

STATEMENT OF DAVID C. CROWLEY, EXECUTIVE VICE PRESIDENT, AMERICAN ASSOCIATION OF HOMES FOR THE AGING, ACCOMPANIED BY LAURENCE F. LANE, DIRECTOR, PUBLIC POLICY

Mr. CROWLEY. Thank you very much, Mr. Chairman.

Mr. Chairman and members of the committee, I am David C. Crowley, executive vice president of the American Association of Homes for the Aging. Accompanying me this morning is Laurence F. Lane, who is our director for public policy.

The American Association of Homes for the Aging represents nonprofit, community-sponsored housing, homes for the aging and health-related facilities serving the elderly throughout the United States. About 250,000 older Americans live in over 1,500 AAHA-member homes, which are sponsored by various religious, fraternal, labor, civic and county organizations. In providing a wide range of living arrangements for elderly persons, ranging from skilled nursing to independent living, these facilities serve a vital role in communities throughout the country.

Because of our commitment toward meeting the needs of older Americans and providing them with quality care, we are very much concerned with the National Energy Act, as passed by the House of Representatives. While this legislation represents a good faith effort to address our current energy crisis, we have serious reservations about its scope and impact.

Specifically, we wish to call to the committee's attention to title II, part III, subpart B—Return of Crude Oil Equalization Taxes. Under the bill, title II, part III, subpart A, an excise tax is imposed on the purchase of all domestically produced crude oil. The purpose of this tax is to increased the cost of all crude oil to equal the world price by 1980. The legislation also provides for a series of tax credits and special payments which are intended to refund to the general public the full amount of the additional revenues collected in 1978 as a result of the crude oil equalization tax—title II, part III, subpart B. Under this section, an exception from the crude oil equalization tax is provided for all hearing oil used in residences, churches, schools, universities, and hospitals. Distributors of heating oil are authorized to receive a refund of the equalization tax for each gallon of heating oil sold to one of these users, so long as the refund is passed through completely to these customers in lower prices—section 2039.

This section would appear to exclude nonprofit long-term care facilities for the elderly from receiving the rebate of the crude oil equalization tax. This is a serious oversight which will impact most severely on nonprofit providers of services to the elderly, as well as their elderly residents. Furthermore, because many of these facilities either participate in the medicaid program to provide skilled or intermediate care and/or rely upon the domiciliary supplement of the SSI program as the means of support for residents, the increased energy costs translate into higher costs for both Federal and State assistance programs.

Operating costs have risen astronomically for all homes for the aging in recent years. The total operating costs for nursing homes rose from $7.45 billion in 1974 to $10.6 billion in 1976, a 70-percent increase. Much of this increase was due to the great rise in fuel prices.

An example of how the current energy situation has impacted on nonprofit homes for the aging can be taken from the experience of facilities in the Cleveland, Ohio, area. During the past winter, the temperature never rose above freezing in that part of the country, with it being below zero on 42 days. In January 1977, a home for the aging in Cleveland used 9 percent more fuel than in the previous year, yet, incurred a 78-percent increase in cost. It is clear that these nonprofit providers of services to the elderly cannot pay for this dramatic rise in fuel costs, as well as the additional crude oil equalization tax, and continue to provide quality care to their elderly residents.

The fuure is bleak for these facilities. They cannot obtain additional funds from their residents to pay for their rising fuel costs, as these individuals are, in almost all cases, living on fixed incomes. Most are poor. A recent congressional study found that 69 percent of the residents in nursing homes have an annual income of under $3,000.

Nonprofit homes for the aged are in an extreme predicament and desperately need Federal assistance to cope with the costly problems resulting from the energy crisis. Otherwise, some facilities may be forced to close and their residents displaced.

If these facilities suspend operations because of their inability to meet high fuel prices, what will happen to their residents? From a Federal budgetary perspective, as well as taking into account human and emotional considerations, it would certainly be much less costly and less traumatic for residents to refund the crude oil equalization tax imposed on fuel used by nonprofit homes for the aging, rather than provide total governmental support for displaced elderly persons.

The facilities which we speak of are those which are exempt from Federal taxation as nonprofit homes for the aging by complying with the strict requirements of the Internal Revenue Service, as articulated in Revenue Ruling 72-124. Under this ruling a home for the aged must provide for three basic needs of elderly persons in order to be tax exempt: (1) the need for housing; (2) the need for health care; and (3) the need for financial security.

These facilities cannot continue to adequately provide for these needs of their elderly residents, while at the same time pay for increased energy costs, including the crude oil equalization tax. If the over 5,000 nonprofit homes for the aged in America are to continue providing quality care to 500,000 elderly individuals, they must receive governmental recognition of their financial needs. It is a gross oversight for a tax rebate program to recognize hospitals, schools, universities and churches and yet omit nonprofit homes for the aging. Nonprofit homes for the aging desperately need to be included in the class of institutions which are exempt from the crude oil equalization tax.

I also wish to call to the committee's attention another serious problem which confronts nonprofit facilities for the elderly. While this concern is not directly within the committee's jurisdiction, and has been discussed in testimony before the Senate Committee on Energy and Natural Resources, it should be considered by the committee as it explores the various legislative alternatives for addressing our present energy crisis.

In the attempt to expedite consideration of part C of the President's energy proposal, the Senate has substituted the provisions of S. 701. Unlike the House legislation which provides assistance to facilities which meet the definitions of section 1633 of the Public Health Act, S. 701 only provides energy conservation improvement grants to hospitals and schools. We believe the House provisions of subpart C are too narrowly defined to include homes for the aging that provide socially intense congregate environments, that language citing the Public Health Act at least provides coverage to nonprofit long-term care facilities that provide medical services.

We urge the Senate to reconsider the eligibility for energy conservation grants to provide coverage for all nonprofit long-term care facilities, or at a minimum, eligibility for skilled and intermediate care facilities under not-for-profit auspices.

Nonprofit homes for the aging were established out of a charitable motivation to provide for the health and social needs of our elderly population. The average age of our member homes is 33 years, with several of our facilities being over 100 years old. When these facilities were constructed, there was little knowledge available about energy conservation techniques and materials. Since the majority of these facilities were financed with charitable donations and public funds, every effort was made to minimize costs.

Furthermore, many were built at a time when there was minimal concern about our energy supply and conservation and as a result, some facilities were constructed with limited insulation, inefficient heating systems, and inadequate weatherproofing.

Clearly, there is a need for initiating and implementing energy conservation measures in these facilities. Unfortunately, as noted previously, these facilities because of their nonprofit status, do not have the revenues to undertake such energy conservation measures in their physical plants. As we move from a consumption-oriented society to a resource-oriented society, with a major emphasis on conservation, it is imperative that these nonprofit facilities, providing vital services to our elderly population, be assisted through Government programs.

Therefore, I respectfully request that the committee consider how governmental assistance might be offered to these facilities for purchasing and installing energy conservation measures.

In conclusion, we urge that the committee take action to include nonprofit homes for the aging in the class of institutions which are exempted from the crude oil equalization tax. Additionally, I ask that the committee explore how governmental assistance could be given to these facilities to assist them in undertaking energy-conservation measures.

It is only through such governmental recognition and aid that nonprofit homes for the elderly can continue to provide quality care to their elderly residents.

We appreciate having this opportunity to appear before the committee, and will be pleased to respond to any questions that you have.

The CHAIRMAN. Thank you very much.

Have your association members done all that can be done to insulate their homes?

Mr. CROWLEY. Mr. Chairman, we have a diverse group of homes. Several of our homes with a longstanding history are quite old. They were bought at a time when there was not an emphasis on energy conservation and they have been taking measures, as individuals have been, to insulate their homes, but we have the problem of dealing with low-income people that we are serving; inadequate reimbursement under the medicaid programs; and the shriveling charitable dollars. It is getting more and more difficult to do this.

While some are able to make plant changes and some facilities have been constructed in recent years, we still have a great number of older buildings that need this kind of support.

The CHAIRMAN. It seems to me that the first order of priority would be to give you whatever help we can to assure that those homes would be insulated as tightly and thoroughly as they can be insulated, because you would save a lot of energy with insulation.

Mr. CROWLEY. We feel this way also, Mr. Chairman.

Mr. LANE. This was the essence of our statement before the Committee on Energy and Natural Resources. There is a need for great assistance so there can be adequate conservation.

At the same time, it is important to note that the crude oil tax that we are speaking of this morning would be passed on, generally, to the medicaid program and/or to the State supplement under SSI. It would be one tax mechanism that either would have to be passed on to the State reimbursement programs as force reduced services. The homes would be caught in the middle of paying it and hoping the reimbursement system would reflect it.

If the tax eats up the money, there will not be the charitable support that is necessary to either match the grants of conservation and/or to initiate efforts of their own to improve the physical plant.

The CHAIRMAN. I am going to instruct the staff to see that the problem is drawn to our attention.

Thank you very much, Mr. Crowley.

Mr. CROWLEY. Thank you, Mr. Chairman.

The CHAIRMAN. Next, we will hear from a witness from the General Electric Co. That will be Mr. Richard C. Barnett, manager of marketing for GE.

We are pleased to have you, Mr. Barnett. We are happy to have your statement.

STATEMENT OF RICHARD C. BARNETT, MANAGER OF MARKETING, GENERAL ELECTRIC CO.

Mr. BARNETT. Thank you, sir.

Mr. Chairman and members of the committee, I appreciate the opportunity to appear this morning before the Senate Committee on Finance. My name is Dick Barnett. I am representing the General Electric Co.'s Air-conditioning Business Division, which is headquartered in Louisville, Ky., and has manufacturing locations in Louisville, Ky.; Columbia, Tenn.; Tyler, Tex.; Trenton, N.J.; and Fort Smith, Ark.

I have been associated with GE's air-conditioning business for about 12 years, having worked in engineering in various gas heating, electric heating and cooling, and heat pump design assignments. Recently, I have held positions in product planning and market development in the marketing end of the business. I have been on my present assignment as manager of marketing for about 1 year.

The air-conditioning industry can be segmented into three major categories: large field engineered systems, room units, and unitary equipment. Unitary equipment is most often used for residential and light commercial applications. The heat pump being used today for space heating in residential and light commercial application is a part of the unitary air-conditioning industry.

The Air-conditioning Business Division of the General Electric Co., manufactures heating and air-conditioning products which serve residential, commercial, and industrial markets. The GE product line includes gas, oil, and electric heating devices as well as electric vapor compression cooling and heat pump systems.

With space heating using 18 percent of the Nation's energy and cooling using 3 percent, the design and manufacture of these products play an important part in the conservation of the Nation's energy. This statement outlines the Air-conditioning Business Division's recommendations for the National Energy Act.

Energy for space heating can be saved by shifting the fuel from scarce natural gas and oil to more abundant electrical power which can be generated from a variety of fuels. Second, by using the heat pump energy savings of 30 to 60 percent over electric resistance heating can be realized.

Future energy supplies of all forms will become more expensive driving the economics in favor of more efficient equipment. Our estimate is that the price of natural gas will increase on a constant dollar basis and a current dollar basis faster than oil or electricity.

NATURAL GAS

With natural gas universally recognized as a scarce natural resource, it follows that the availability will be a function of price. If price controls are lifted, natural gas will become more available at a significantly higher price. If price controls are continued, natural gas will increasingly be curtailed.

The realization that natural gas is scarce and that there are essential uses for natural gas which if not satisfied would have severe implications, leads us to believe that natural gas should not be used for low-quality space-heating needs, but conserved for essential uses in medicines, fertilizers, synthetic fibers, plastics, and high-quality process heating.

Space heating only requires temperatures in the 80° to 200°F range, while natural gas produces temperatures in the 2,500° range. Many processes require higher temperatures which can only be satisfied by direct combustion of a fossil fuel. Space heating can be accomplished from a variety of sources such as the heat pump.

OIL

Oil is also limited, but domestically available through high imports which are steadily increasing. Oil is essential for transportation as no economic substitute is currently known for gasoline, diesel fuel, or jet fuel. Our domestic production of oil will not cover our transportation needs. However, imports can be reduced by substituting electrical energy with the heat pump for space heating needs.

ELECTRICITY

Electrical energy is generally available with all but a few electric utilities summer peaking. Electric power is currently being generated from a variety of fuels.

Population movement trends are favorable to reduce oil and natural gas in electrical power generation.

Save scarce reserves of natural gas and oil for those purposes which they alone can satisfy. Extend the limited supply and reduce dependency on imports by using electrical power for space heating.

Use electrical power efficiently by using the heat pump rather than resistance heating.

Heat pumps use a vapor compression cycle to literally pump heat from a cooler ambient to a warmer ambient. Normally, heat flows from a warm source to a cooler sink. The heat pump uses electrical energy as work to pump heat up the "thermal hill," from a cooler sink to the warmer source. A refrigerator is a type of heat pump, pumping heat from inside the cabinet and rejecting the heat to the warmer kitchen.

An air-conditioner is also a type of heat pump, pumping heat from the cool inside to the warm outside air. In cooling a heat pump does exactly the same thing. In heating, the refrigerant is reversed and heat is absorbed from the cool outdoor air and is rejected to the indoor air. The heat pump does not create heat but moves it from one place to another using electrical power as work energy. Even at 0°F there is 89 percent as much heat in the outdoor air as at 100°F. The heat pump uses this replenished natural resource.

Heat pumps save 30 to 60 percent over electric resistance heating depending on the area of the country and associated climate. By way of one specific example, studies by the FEA, published in their Energy Saving Calculator show savings for heat pumps in a climate similar to Atlanta, Ga., to be 32.5 percent over electric resistance heating, while storm doors achieve a 2.1-percent; increasing wall insulation from 2 to 3.5 inches, 3.8 percent; increasing ceiling insulation from 2 to 6 inchs, 9.5 percent; and storm windows, 17.9 percent.

These, of course, are generalized savings, and savings for a specific location may vary. It does clearly indicate that heat pumps can account for as much savings as all the other major factors combined. If tax credits are to be awarded for storm windows and doors, insulation and clock thermostats, it seems appropriate to award tax credits for heat pumps as well.

In new construction or the retrofit market, heat pumps can replace or be used in combination with fossil fuel furnaces to save scarce natural gas and oil. In general, heat pumps provide 70 to 90 percent of the heating for a home; 10 to 30 percent of the home heating is contributed by supplemental heaters which are required in virtually all geographic areas of the country.

Normally, this supplemental heat is accompanied by electric resistance heaters. Supplemental heat can be accomplished by alternate methods, such as a fossil fuel furnace. Using a heat pump in conjunction with a fossil fuel furnace can save scarce fossil fuel by substituting electrical energy. In addition, using fossil fuels for supplemental heating can save electric peak power demand which is a substantial benefit on the electric utility.

There are many industry programs which will improve the energy savings attainable with heat pump systems. Many of these programs will improve the already excellent efficiency of the heat pump itself through improved heat exchangers, motors and refrigeration cycles and components. Other programs will improve the heat pump system by coupling the heat pump with solar collector panels or fossil fuel supplementary heating systems.

The heat pump is not only a viable option for heating and cooling today, but prepares the consumer for future energy savings as more advanced systems are developed.

The General Electric Co. supports the use of tax credits to encourage the consumer to buy energy-saving products. Many components such as automatic ignition devices for gas furnaces and appliances, flue dampers for gas furnaces to reduce stack losses, night setback thermostats and solar energy are already specifically included in the pending bill.

Most of these energy saving devices are already on the market and being demanded on an ever-increasing scale by the consumer. Tax credits will reinforce the acceptance of these products by making the payoff more favorable and by demonstrating the Government's recognition of the devices as an energy conservation method.

We strongly recommend heat pumps be included in the proposed bill to provide the same beneficial market influences as now proposed for the other energy conservation items. A tax credit amounting to 20 percent of the cost of a heat pump system to a maximum of $400 per credit would be a significant motivational factor to encourage the consumer to opt for the higher first cost heat pump system.

It would also contribute to the Nation's growing balance of payments problems from switching from fossil fuels to electropower and can be generated from whatever natural resources most available and least expensive.

Again, we would like to thank you for the opportunity this morning and stand ready to answer any questions you might have.

The CHAIRMAN. Let me ask about one matter.

It seems to me that for some time to come we are going to be using natural gas to generate power for air-conditioning, or for heat as the case may be. As long as you are heating the home, do you not get a far more efficient use of gas by burning it inside the building and by capturing all the heat that can be captured at that point, rather than by generating electricity and pushing it through a wire to a heat pump?

Mr. BARNETT. Senator, that varies somewhat by geographical location, but in general, it is about equal. The utility power generation efficiency is in the neighborhood of about 33 percent, which means that out of 100 units of energy delivered to the power station in natural gas, you only get 33 units of energy available in electric power. You then lose another 10 percent of that energy in distribution to the home. Now you end up with 30 units of the original 100 units of energy available to the consumer.

Now, it is true that if you use that for electric resistance heating, you would only get 100 units of energy out of that for useful space heat. In the case of the heat pump, we utilize the electrical energy for our work to pump heat from the outdoor air.

In effect, on the average for the United States you get about a seasonable performance factor of 2 which means every one unit of electric energy you put into the home for heating, you pick up an additional unit of energy from the outdoor air and actually deliver two units of energy.

So for that 30 units of electrical energy you have delivered to the home by use of the heat pump, you can now convert that into 60 units of heating energy delivered to the home.

If you look at a gas furnace on a seasonal basis, you get about a 60-percent efficiency.

The CHAIRMAN. What I am proposing is to burn the gas right inside the house, to get the most efficiency, to not let anything go up the stack that can be kept from going up the stack. Of course, the way it used to be done before the environmental movement was to burn the gas right inside the house, to have an old-fashioned space heater without an exterior flue. Obviously, with that method, 100 percent of the heat is inside the house. There are still some of those old heaters down in my part of the country.

With gas-fired generators, can you do anything but lose a lot of the Btu's when you put the electricity through a wire and bring the wire to a house to operate the heat pump?

Mr. BARNETT. No, sir. The heat pump allows electrical energy heating to be on the same energy efficiency basis on the combustion fuels. Obviously, there are going to be some improvements in direct combustion of fossil fuels, direct spark ignition to reduce the losses of standing pilots with flue dampers to reduce the offsite loss of heat going up the stack. The gas furnace efficiency, on a seasonal basis, is going to improve.

The same type of improvements will also take place in heat pump systems and we believe you will have an equally efficient utilization of natural resources by using the heat pump as direct combustion to natural gas.

The advantage, of course, is that you can generate electricity from a variety of sources, and as you see in the statement, sir, the electrical energy industry is predicting that natural gas utilization for power generation will drop off substantially between now and 1982. This is true even in the Southwest where they are planning to use lignite and other types of more abundant fuels to generate power.

The CHAIRMAN. I can see how, with electric power from coal or lignite, the heat pump would be a dandy device. I can see that. In fact, I am getting some familiarity with the heat pump right now. My neighbor has one and likes it; he seems to think they are good.

We have not had much experience with them, but my neighbors seem to think it is a good thing. I doubted that there were savings from switching over from natural gas right burned inside the house. You are saying, compared to the kind of gas furnaces that are being used now, that the heat pump is competitive even now.

Mr. BARNETT. Yes, and the opportunity is to shift from natural gas to coal and hydro and more abundant fuels and save that scarce resource of natural gas for things that it alone can satisfy, like process heat and medicines.

The CHAIRMAN. Right.

Well, thank you very much for a very useful statement.

Senator Matsunaga?

Senator MATSUNAGA. Thank you, Mr. Chairman.

How long has this heat pump been in operation and on the market?

Mr. BARNETT. Heat pumps were introduced on a pilot basis on the market back in 1932. The heat pump industry really did not get started until the midsixties and basically the industry sold about 80,000 units a year up till about 1973 when natural gas started to be curtailed throughout the Midwest.

Since that time, the heat pump industry has grown quite nicely and this year it is anticipated about 450,000 units will be sold in the industry. So the heat pump is a viable device. It is not anything revolutionary and new. It is done with proven concepts and components.

Senator MATSUNAGA. You say you have succeeded in marketing the heat pump. You have also stated that it saves 30 to 60 percent you say, in energy—as compared to what other form of energy?

Mr. BARNETT. Compared to electric resistance type heating, it will save 30 to 60 percent.

Senator MATSUNAGA. Even without any tax incentive, would you not be able to sell the heat pump?

Mr. BARNETT. Even without the tax incentive, the heat pump industry is going to grow. If natural gas continues to be curtailed, it becomes the only viable way to heat a new residence in much of the United States.

There is a big existing inventory, however, of natural gas furnaces and oil furnaces which could be shifted from those scarce fossil fuels to electrical energy with the heat pump, if tax credits were provided.

In addition, many builders often put in the lowest first-cost system and many consumers are unaware of the heat pump's ability to save energy. Certainly the industry is trying to identify to the consumer these energy savings capabilities and, if tax credits were allowed, it would support that claim by the industry and provide a lot of credence to the industry trying to identify to the public that it is an energy-saving device.

Senator MATSUNAGA. I do not fully understand how the heat pump operates. What do you do about bringing in fresh air?

Mr. BARNETT. Fresh air can be included into the system in any way that any other central air-conditioning system would utilize it. A certain amount of pressure could be brought in by separate duct systems or preferably—a separate duct system where it will go through the filtration system so the air is clean as well.

Senator MATSUNAGA. By having a system of fresh air entering in, will you reduce the efficiency of the heat pump?

Mr. BARNETT. In general, the amount of fresh air induced into the space being conditioned is modulated with the outdoor temperature. In most residences, the fresh air comes in naturally as the doors are opened and closed and there is no positive fresh air intake to the residence as it is with the central heating and cooling system of any other type.

In the case of many commercial installations, however, fresh air is introduced through the facility. Therefore, the effect on the efficiency or the energy use would not be any different with the heat pump than with any other heating and cooling system.

As we are gaining knowledge and concern for energy use, we are seeing a great number of sales of what we call an economizer cycle, which is a damper-like system modulated and controlled by outdoor temperature and indoor temperature controls to actually accomplish free cooling and minimize fresh air intake into what is only required when heating loads get high.

So these controlled systems are being introduced in the marketplace and going into many commercial installations.

Senator MATSUNAGA. What about installation? Is it a complicated matter?

Mr. BARNETT. Not really. It is more difficult than installing a gas furnace and an electric air-conditioning system.

Senator MATSUNAGA. Do you have any portable window units or other types of heat pumps which can be carried from room to room?

Mr. BARNETT. In general, these are central systems which have a fixed duct system and you circulate the air in the room over the heating system. There are some models being introduced now which are a through-the-wall type of system, but it is still, in general, a fixed heat-pump system.

Senator MATSUNAGA. If we should grant the tax credit which you propose, what is your projected sale and if your projected sales are met, are you able to produce enough of it to supply the market?

Mr. BARNETT. Yes.

We think by 1982 the industry could go as high as 1 million units a year if the tax credits were allowed.

Senator MATSUNAGA. 1982?

Mr. BARNETT. Yes. If, however, the industry grew to that extent, the air-conditioning industry would be able to satisfy the consumers' demand.

Senator MATSUNAGA. Is there any other firm producing the same product?

Mr. BARNETT. There are 62 manufacturers of heat pumps listed in the current Air Conditioning/Refrigeration Directory.

Senator MATSUNAGA. All under contract with GE?

Mr. BARNETT. No, sir. We do not sell our equipment to any other manufacturer. We simply sell it under our own brand.

There are a few manufacturers who do, but basically the major manufacturers sell their own products.

Senator MATSUNAGA. It sounds very interesting.

The CHAIRMAN. Let me ask you about this aspect of the heat pump proposal.

On the House side, they looked at this proposal and found that the heat pump is used more for air-conditioning than it is for heating, did they not? Is that the attitude in the House? The House committee took the view that the heat pump was used more for air-conditioning than it was for heating?

Mr. BARNETT. I do not have direct knowledge of that.

The CHAIRMAN. You made a good statement here, but you did not win on the House side. I am trying to figure out why they took the view that this heat pump is used a lot more for air-conditioning than it is for heating. They seemed to take the view that one would save a lot more energy rather than using the heat pump to cool the home in summertime, if people just did what they do now, open up the windows and turn on old-fashioned electric fans.

How would the cost of the heat pump compare to the electric fan?

Mr. BARNETT. I am not sure that is an equitable comparison. The heat pump definitely does have built into it——

The CHAIRMAN. Better than that, one saves more energy just by sweating at night.

I am not saying it is always the most comfortable way to go, but it is not bad for your health to perspire some during the year. Comparing the electric fan and the central fan that circulates air, pulling air through the house, these methods are cheaper than the heat pump.

Mr. BARNETT. The power consumed with the heat pump versus the electric fan would be considerably more for the heat pump. The fact is, however, that central air-conditioning is being demanded by the consuming public in new construction. About 60 percent of new construction is going with central air-conditioning and one of the reasons the industry will be able to serve the heat pump market is because it is simply going to be a shift of products from air-conditioners that use the same type of compressors and components as are used in heat pumps to a heat pump type of unit. So the industry will not necessarily sell any more air-conditioners. It is the type of heating system that will go with the air-conditioner that will go in anyway that will change from the gas or electric resistant device to a heat pump.

The CHAIRMAN. It seems to me that it might make money for the Government rather than cost us money if we just provided, instead of a tax advantage for the heat pump, a tax on the electric resistance heater, because that is the kind of device you are competing with. Your thought is, as I understand it, that it is far cheaper than electric resistance to heat a house by heat pump. Even, I believe you said, if it is 0° outside?

Mr. BARNETT. On a seasonal basis, it is far cheaper, yes.

The CHAIRMAN. Right, As a heating unit, a heat pump is more efficient than an electric resistance heater?

Mr. BARNETT. There are some places within the country that an electric resistance heating system might make sense in mountainous areas, in the Pacific Northwest, where cooling is not required, they may opt for a heat pump system and where electric rates are still very low because they generate basically from hydro and nuclear, that electric resistance heating still might make sense in those areas.

Putting a tax on electric resistance heat may not be the appropriate choice.

In addition to that, if you single out electric resistance heat for a penalty, it does not provide any incentive or any encouragement to switch from a scarce fossil-fuel-type heating system to a heat pump heating system which, of course, is the point I made before about fuel generation.

The CHAIRMAN. It is obviously a development that is a coming thing. It appears to be the best device we have right now. I think maybe when we get into executive session you ought to bring one of those heat pumps up here and demonstrate it in this room, and how it works, to people on this committee so they can understand it.

Senator Matsunaga, the best way I can illustrate it would be for you to think of it as you do your refrigerator, think of yourself inside a refrigerator. That is a heat pump, except that it is making it cool inside.

Now, if you picture yourself being inside a big refrigerator and just ran the pump backwards, it would get hotter than Hades in there. That is basically the idea, is it not?

Mr. BARNETT. Absolutely.

Senator MATSUNAGA. Is it a misnomer to call it a heat pump?

Mr. BARNETT. There is a great deal of discussion about that.

Senator MATSUNAGA. If it is primarily intended for air-conditioning rather than heating——

Mr. BARNETT. The heat pump is really a heating device. It also has the capability of cooling with it. The energy savings associated with the heat pump are, in general, associated with heating and not air-conditioning, but it is both a heating and a cooling unit.

Senator MATSUNAGA. You use this same unit for heating and cooling?

Mr. BARNETT. Yes, sir.

Senator MATSUNAGA. You just switch from one to the other?

Mr. BARNETT. That is correct. The room thermostat would be positioned for either heating or cooling mode, and the system would take care of it.

Senator MATSUNAGA. Is it fully electric?

Mr. BARNETT. Yes, it is.

Senator MATSUNAGA. I have no further questions.

The CHAIRMAN. Thank you very much.

[The prepared statement of Mr. Barnett follows:]

STATEMENT OF THE GENERAL ELECTRIC CO.

SUMMARY

The population is shifting to geographical areas where electrical power is coal generated and heat pumps are favorable.

The heat pump makes space heating with electrical power as energy efficient as heating by direct combustion of natural gas or oil.

The heat pump can conserve scarce fossil fuels by:

1. Shifting the use of energy for space heating from natural gas and oil to electrical power generated from coal, hydro and nuclear fuels.

2. Heating with electricity is the most efficient manner known today (heat pump), saving 30 to 60 percent over electric resistance heating.

Tax credits are recommended to encourage the consumer to buy the higher first cost heat pump system and demonstrate the government's support of heat pumps as an energy conservation system.

STATEMENT

Mr. Chairman, I appreciate the opportunity to appear this morning before the Senate Committee on Finance. My name is Dick Barnett. I am representing the General Electric Company's Air Conditioning Business Division, which is headquartered in Louisville, Ky., and has manufacturing locations in Louisville, Ky., Columbia, Tenn., Tyler, Tex., Trenton, N.J., and Fort Smith, Ark.

I have been associated with GE's Air Conditioning business for about twelve years, having worked in engineering in various gas heating, electric heating and cooling and heat pump design assignments. Recently, I have held positions in product planning and market development in the marketing end of the business. I have been on my present assignment as Manager of Marketing for about a year.

The air conditioning industry can be segmented into three major categories: large field engineered systems, room units, and unitary equipment. Unitary equipment is most often used for residential and light commercial applications. The heat pump being used today for space heating in residential and light commercial application is a part of the unitary air conditioning industry.

The Air Conditioning Business Division of the General Electric Company manufactures heating and air conditioning products which serve residential, commercial and industrial markets. The GE product line includes gas, oil and electric heating devices as well as electric vapor compression cooling and heat pump systems. With space heating using 18 percent of the nation's energy and cooling using 3 percent, the design and manufacture of these products play an important part in the conservation of the nation's energy. This statement outlines the Air Conditioning Business Division's recommendations for the National Energy Act.

HEATING FUELS FOR U.S. HOMES

[In percent]

	1973	1976	1982 estimate
Heat pump	2	12	23
Electric resistance	46	40	38
Subtotal electric	48	52	61
Oil	8	9	11
Natural gas	43	38	26
Other	1	1	2
Total	100	100	100

Energy for space heating can be saved by shifting the fuel from scarce natural gas and oil to more abundant electrical power which can be generated from a variety of fuels. Secondly, by using the heat pump energy savings of 30 to 60 percent over electric resistance heating can be realized.

Residential, Comfort Conditioning:
Natural gas curtailed east of Mississippi for new construction.
Natural gas low priced for existing buildings.
Oil available from imports.
Electricity readily available with utilities—summer peaking.
Commercial, Space Heating:
Natural gas readily available at controlled prices.
Oil available from imports.
Electricity readily available with utilities—summer peaking.
Industrial Space Heating:
Natural gas available at controlled low price but subject to peak period curtailment.
Oil available largely from imports.
Electricity available with utilities—summer peaking.
Industrial, Process Heat:
Natural gas controlled at low prices and yields high quality energy.
Oil is generally not used.
Electricity cannot satisfy many process heat needs, i.e., brazing.

Future energy supplies of all forms will become more expensive driving the economics in favor of more efficient equipment. Our estimate is that the price of natural gas will increase on a constant dollar basis and a current dollar basis faster than oil or electricity.

AVERAGE ANNUAL INCREASE

[In percent]

	1977-82	
	Constant dollars	Current dollars
Electricity	2.0	8.4
Natural gas	9.3	15.7
Oil	2.0	8.4

ENERGY SCENARIO

Natural Gas.—With natural gas universally recognized as a scarce natural resource, it follows that the availability will be a function of the price. If price controls are lifted, natural gas will become more available at a significantly higher price. If price controls are continued, natural gas will increasingly be curtailed.

The realization that natural gas is scarce and that there are essential uses for natural gas which if not satisfied would have severe implications, leads us to believe that natural gas should not be used for low quality heating needs, but conserved for essential uses in medicines, fertilizers, synthetic fibers, plastics and high quality process heating.

Space heating only requires temperatures in the 80-200°F range, while natural gas produces temperatures in the 2500°F range. Many processes require higher temperatures which can only be satisfied by direct combustion of a fossil fuel. Space heating can be accomplished from a variety of sources such as the heat pump.

Oil.—Oil is also limited, but domestically available through high imports which are steadily increasing. Oil is essential for transportation as no economic substitute is currently known for gasoline, diesel fuel or jet fuel. Our domestic production of oil will not cover our transportation needs. However, imports can be reduced by substituting electrical energy with the heat pump for space heating needs.

Electricity.—Electrical energy is generally available with all but a few electric utilities summer peaking. Electric power is currently being generated from a variety of fuels:

ELECTRIC POWER GENERATION[1]

[In percent]

	1977 estimate	1982 estimate
Natural gas	11.7	5.6
Oil	17.1	17.6
Coal	47.0	47.8
Hydro	11.1	8.5
Nuclear	13.1	20.5
Total	100.0	100.0

[1] 1977 Annual Electric Power Survey.

Population movement trends are favorable to reduce oil and natural gas in electrical power generation.

POPULATION TRENDS BY REGION

	Predominate power generation fuel	1970 population	Percent change 1975-80	Percent change 1980-85	Percent inclusion of AC
Northeast	Oil	49.1	0.4	2.4	25
North Central	Coal	56.6	1.9	3.7	43
South	do	62.8	8.1	7.6	79
West	Mixed	34.8	5.3	5.8	37
Total		203.3	4.1	5.1	55

Conclusions Energy Scenario—Save scarce reserves of natural gas and oil for those purposes which they alone can satisfy. Extend the limited supply and reduce dependency on imports by using electrical power for space heating.

Use electrical power efficiently by using the heat pump rather than resistance heating.

HEAT PUMP SYSTEMS

Heat pumps use a vapor compression cycle to literally pump heat from a cooler ambient to a warmer ambient. Normally, heat flows from a warm source to a cooler sink. The heat pump uses electrical energy as work to pump heat up the "thermal hill", from a cooler sink to the warmer source. A refrigerator is a type of heat pump, pumping heat from inside the cabinet and rejecting the heat to the warmer kitchen.

An air conditioner is also a type of heat pump, pumping heat from the cool inside to the warm outside air. In cooling, a heat pump does exactly the same thing. In heating, the refrigerant is reversed and heat is absorbed from the cool outdoor air and is rejected to the indoor air. The heat pump does not create heat but moves it from one place to another using electrical power as work energy. Even at 0°F there is 89 percent as much heat in the outdoor air as at 100°F. The heat pump uses this replenished natural resource.

The heat pump saves energy

Heat pumps save 30 to 60 percent over electric resistance heating depending on the area of the country, and associated climate. By way of one specific example, studies by the FEA, published in their Energy Saving Calculator, show savings for heat pumps in a climate similar to Atlanta, Ga. to be 32.5 percent over electric resistance heating, while storm doors achieve 2.1 percent, increasing wall insulation from 2 to 3.5 inches 3.8 percent, increasing ceiling insulation from 2 to 6 inches 9.5 percent and storm windows 17.9 percent. These, of course, are generalized savings, and savings for a specific location may vary. It does clearly indicate that heat pumps can account for as much savings as all the other major factors combined. If tax credits are to be awarded for storm windows and doors, insulation and clock thermostats, it seems appropriate to award tax credits for heat pumps as well.

Heat pumps can save fossil fuels

In new construction or the retrofit market, heat pumps can replace or be used in combination with fossil fuel furnaces to save scarce natural gas and oil. In general, heat pumps provide 70 to 90 percent of the heating for a home. 10 to 30 percent of the home heating is contributed by supplemental heaters which are required in virtually all geographic areas of the country. Normally, this supplemental heat is accomplished by electric resistance heaters. Supplemental heat can be accomplished by alternate methods, such as a fossil fuel furnace. Using a heat pump in conjunction with a fossil fuel furnace can save scarce fossil fuel by substituting electrical energy. In addition, using fossil fuels for supplemental heating can save electric peak power demand which is a substantial benefit on the electric utility.

Heat pumps offer potential for future energy savings

There are many industry programs which will improve the energy savings attainable with heat pump systems. Many of these programs will improve the already excellent efficiency of the heat pump itself through improved heat exchangers, motors and refrigeration cycles and components. Other programs will improve the heat pump system by coupling the heat pump with solar collector panels or fossil fuel supplementary heating systems. The heat pump is not only a viable option for heating and cooling today, but prepares the consumer for future energy savings as more advanced systems are developed.

Tax credits

The General Electric Company supports the use of tax credits to encourage the consumer to buy energy saving products. Many components such as automatic ignition devices for gas furnaces and appliances, flue dampers for gas furnaces to reduce stack losses, night set-back thermostats and solar energy are already specifically included in the pending bill. Most of these energy saving devices are already on the market and being demanded on an ever increasing scale by the consumer. Tax credits will reinforce the acceptance of these products by making the payoff more favorable and by demonstrating the government's recognition of the devices as an energy conservation method.

We strongly recommend heat pumps be included in the proposed bill to provide the same beneficial market influences as now proposed for the other energy conservation items. A tax credit amounting to 20 percent of the cost of a heat pump system to a maximum of $400 tax credit would be a significant motivational factor to encourage the consumer to opt for the higher first cost heat pump system.

Tax recommendations

To inspire the expanded use of heat pump systems in all markets for increased energy savings, tax credits would partially offset the higher first cost of heat pump systems. The following table is a calculation of one area of the country—Philadelphia.

SYSTEM COST ANALYSIS (PHILADELPHIA)

Component	New construction/cooling				Heat pump retrofit		
	Gas furnace	Oil furnace	Electric furnace	Heat pump	Gas furnace	Oil furnace	Electric furnace
Equipment:							
Heating	$280	$580	$365	$1,470	$1,300	$1,300	$1,300
Cooling	770	770	770				
Air duct	1,350	1,350	1,350	1,350	100	100	100
Power:							
Gas	65						
Oil (tank)		320					
Electric	150	150	200	200	100	100	100
System cost	2,615	3,170	2,685	3,020	1,500	1,500	1,500
Heating cost	570	680	1,000	530	485	510	600
Tax credit on equipment				294	260	260	260
Pay back period (heat pump versus):							
No tax credit (years)	10.0		0.7		17.6	8.8	3.75
Tax credit (years)	2.8		.1		14.6	7.3	3.1

Note: Energy costs: Gas, $0.30 per therm; oil, $0.46 per gallon; electric, 2.96 cents per kilowatt-hour.

Source: Foregoing data is based on GE estimates.

[Thereupon, at 11:55 a.m., the hearing in the above-entitled matter was recessed, to reconvene at the call of the Chair.]

APPENDIX A

95TH CONGRESS
1ST SESSION

H. R. 8444

[Report No. 95-543]

IN THE HOUSE OF REPRESENTATIVES

JULY 20, 1977

Mr. ASHLEY introduced the following bill; which was referred to the Ad Hoc Committee on Energy for a period ending not later than July 27, 1977

JULY 27, 1977

Reported with amendments, committed to the Committee of the Whole House on the State of the Union, and ordered to be printed

AUGUST 5, 1977

Considered, amended, and passed

AN ACT

To establish a comprehensive national energy policy.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE; TABLE OF CONTENTS.

(a) SHORT TITLE.—This Act may be cited as the "National Energy Act".

(b) TABLE OF CONTENTS.—

TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS

PART I—ENERGY CONSERVATION PROGRAMS FOR EXISTING RESIDENTIAL BUILDINGS

TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS—Continued

TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS—Continued

PART IV—NATURAL GAS—Continued

PART V—PUBLIC UTILITY REGULATORY POLICIES

Chapter 1—GENERAL PROVISIONS

Chapter 2—IMPROVING EFFICIENCY OF USE OF ELECTRICITY

Subchapter A—General Provisions

Subchapter B—National Minimum Standards for State Regulated Electric Utility Rate Regulation

Subchapter C—Other Requirements for State Regulated Electric Utilities

Subchapter D—Nonregulated Utilities

Subchapter E—Requirements Applicable to State Regulatory Authorities

TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS—Continued

Chapter 2—IMPROVING EFFICIENCY OF USE OF ELECTRICITY—Continued

Subchapter F—Enforcement and Review

Chapter 3—IMPROVING EFFICIENCY OF, AND PRESERVING COMPETITION IN, GENERATION AND TRANSMISSION OF ELECTRICITY

Chapter 4—CONSUMER REPRESENTATION AND ASSISTANCE TO STATE AGENCIES

Chapter 5—NATURAL GAS UTILITIES

Subchapter A—General Provisions

Subchapter B—Requirements for Gas Utilities

Subchapter C—Administration, Enforcement, Review

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TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS—Continued

Chapter 6—SMALL HYDROELECTRIC POWER PROJECTS

PART VI—CONVERSION FROM NATURAL GAS AND PETROLEUM TO COAL AND OTHER FUEL RESOURCES

SUBPART A—GENERAL PROVISIONS

SUBPART B—PROHIBITIONS; EXEMPTIONS

SUBPART C—ENFORCEMENT; ADMINISTRATION

SUBPART D—MISCELLANEOUS PROVISIONS

TITLE I—PRICING, REGULATORY, AND OTHER NONTAX PROVISIONS—Continued

Part VII—Federal Energy Initiatives

TITLE II—TAX PROVISIONS

Part I—Residential Energy Credit

TITLE II—TAX PROVISIONS—Continued

Part II—Transportation

SUBPART A—GAS GUZZLER TAX

SUBPART B—MOTOR FUELS

SUBPART C—PROVISIONS RELATED TO BUSES

SUBPART D—CREDIT FOR ELECTRIC MOTOR VEHICLES

Part III—Crude Oil Equalization Taxes

SUBPART A—IMPOSITION OF TAXES

SUBPART B—RETURN OF CRUDE OIL EQUALIZATION TAXES

Part IV—Excise Tax on Business Use of Oil and Natural Gas

Part V—Credit Against Tax on Business Use of Oil and Gas

TITLE II—TAX PROVISIONS—Continued

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TITLE II—TAX PROVISIONS

SEC. 2001. SHORT TITLE.

This title may be cited as the "Energy Tax Act of 1977".

SEC. 2002. AMENDMENT OF 1954 CODE.

Except as otherwise expressly provided, whenever in this title an amendment or repeal is expressed in terms of an amendment to, or repeal of, a section or other provision, the reference shall be considered to be made to a section or other provision of the Internal Revenue Code of 1954.

PART I—RESIDENTIAL ENERGY CREDIT

SEC. 2011. RESIDENTIAL ENERGY CREDIT.

(a) GENERAL RULE.—Subpart A of part IV of subchapter A of chapter 1 (relating to credits allowable) is amended by inserting after section 44B the following new section:

"SEC. 44C. RESIDENTIAL ENERGY CREDIT.

"(a) GENERAL RULE.—In the case of an individual, there shall be allowed as a credit against the tax imposed by this chapter for the taxable year an amount equal to the sum of—

"(1) the qualified energy conservation expenditures, plus

"(2) the qualified solar and wind energy expenditures.

"(b) QUALIFIED EXPENDITURES.—For purposes of subsection (a)—

"(1) ENERGY CONSERVATION.—In the case of any dwelling unit, the qualified energy conservation expenditures are 20 percent of so much of the energy conservation expenditures made by the taxpayer during the taxable year with respect to such unit as does not exceed $2,000.

"(2) SOLAR AND WIND.—In the case of any dwelling unit, the qualified solar and wind energy expenditures are the following percentages of the solar and wind energy expenditures made by the taxpayer during the taxable year with respect to such unit:

"(A) 30 percent of so much of such expenditures as does not exceed $1,500, plus

"(B) 20 percent of so much of such expenditures as exceeds $1,500 but does not exceed $10,000.

"(3) PRIOR EXPENDITURES BY TAXPAYER ON SAME RESIDENCE TAKEN INTO ACCOUNT.—If for any prior taxable year a credit was allowed to the taxpayer under this section with respect to any dwelling unit by reason of energy conservation expenditures or solar and wind energy expenditures, paragraph (1) or (2) (whichever is appropriate) shall be applied for the taxable year with respect to such dwelling unit by reducing each dollar amount contained in such paragraph by the prior year expenditures taken into account under such paragraph.

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"(4) MINIMUM DOLLAR AMOUNT.—No credit shall be allowed under this section with respect to any return for any taxable year if the amount which would (but for this paragraph) be allowable with respect to such return is less than $10.

"(5) APPLICATION WITH OTHER CREDITS.—The credit allowed by subsection (a) shall not exceed the tax imposed by this chapter for the taxable year, reduced by the sum of the credits allowable under a section of this part having a lower number or letter designation than this section, other than the credits allowable by sections 31, 39, and 43.

"(c) DEFINITIONS AND SPECIAL RULES.—For purposes of this section—

"(1) ENERGY CONSERVATION EXPENDITURE.— The term 'energy conservation expenditure' means an expenditure made on or after April 20, 1977, by the taxpayer for insulation or any other energy-conserving component (or for the original installation of such insulation or other component) installed in or on a dwelling unit—

"(A) which is located in the United States,

"(B) which is used by the taxpayer as his principal residence, and

"(C) the construction of which was substantially completed before April 20, 1977.

"(2) SOLAR AND WIND ENERGY EXPENDITURE.—

"(A) IN GENERAL.—The term 'solar and wind energy expenditure' means an expenditure made on or after April 20, 1977, by the taxpayer for solar and wind energy property installed in connection with a dwelling unit—

"(i) which is located in the United States, and

"(ii) which is used by the taxpayer as his principal residence.

"(B) ITEMS INCLUDED.—The term 'solar and wind energy expenditure' includes only expenditures for—

"(i) solar and wind energy property, or

"(ii) labor costs properly allocable to the onsite preparation, assembly, or installation of solar and wind energy property.

"(C) SWIMMING POOL, ETC., USED AS STORAGE MEDIUM.—The term 'solar and wind energy expenditure' does not include any expenditure properly allocable to a swimming pool used as an energy storage medium or to any other energy storage medium which has a function other than the function of such storage.

"(3) INSULATION.—The term 'insulation' means any item—

"(A) which is specifically and primarily designed to reduce when installed in or on a dwelling (or water heater) the heat loss or gain of such dwelling (or water heater),

"(B) the original use of which begins with the taxpayer,

"(C) which can reasonably be expected to remain in operation for at least 3 years, and

"(D) which meets the performance and quality standards which—

"(i) have been prescribed by the Secretary by regulations, and

"(ii) are in effect at the time of the acquisition of the item.

"(4) OTHER ENERGY-CONSERVING COMPONENT.—The term 'other energy-conserving component' means any item (other than insulation)—

"(A) which is—

"(i) a furnace replacement burner designed to achieve a reduction in the amount of fuel consumed as a result of increased combustion efficiency,

"(ii) a device for modifying flue openings designed to increase the efficiency of operation of the heating system,

"(iii) an electrical or mechanical furnace ignition system which replaces a gas pilot light,

"(iv) a storm or thermal window or door for the exterior of the dwelling,

"(v) a clock thermostat,

"(vi) caulking or weatherstripping of an exterior door or window, or

"(vii) an item of a kind which the Secretary specifies by regulations as increasing the energy efficiency of the dwelling,

"(B) the original use of which begins with the taxpayer,

"(C) which can reasonably be expected to remain in operation for at least 3 years, and

"(D) which meets the performance and quality standards which—

"(i) have been prescribed by the Secretary by regulations, and

"(ii) are in effect at the time of the acquisition of the item.

"(5) SOLAR AND WIND ENERGY PROPERTY.—The term 'solar and wind energy property' means property—

"(A) which, when installed in connection with a dwelling—

"(i) uses solar energy for the purpose of heating or cooling such dwelling or providing hot water for use within such dwelling, or

"(ii) uses wind energy for nonbusiness residential purposes,

"(B) the original use of which begins with the taxpayer,

"(C) which can reasonably be expected to remain in operation for at least 5 years, and

"(D) which, when installed in connection with a dwelling, meets the performance and quality standards which—

"(i) have been prescribed by the Secretary by regulations, and

"(ii) are in effect at the time of the acquisition of the property.

"(6) CONSULTATION IN PRESCRIBING STANDARDS.—Performance and quality standards shall be prescribed by the Secretary under paragraphs (3), (4), and (5) only after consultation with the Secretary of

Energy, the Secretary of Housing and Urban Development, and other appropriate Federal agencies.

"(7) WHEN EXPENDITURES MADE; AMOUNT OF EXPENDITURES.—

"(A) Except as provided in subparagraph (B), an expenditure with respect to an item shall be treated as made when original installation of the item is completed.

"(B) In the case of solar and wind energy expenditures in connection with the construction or reconstruction of a dwelling, such expenditures shall be treated as made when the original use of the constructed or reconstructed dwelling by the taxpayer begins.

"(C) The amount of any expenditure shall be the cost thereof.

"(D) If less than 80 percent of the use of an item is for nonbusiness residential purposes, only that portion of the expenditures for such item which is properly allocable to use for nonbusiness residential purposes shall be taken into account. For purposes of the preceding sentence, use for a swimming pool shall be treated as use which is not for residential purposes.

"(8) PRINCIPAL RESIDENCE.—The determination of whether or not a dwelling unit is a taxpayer's principal residence shall be made under principles similar to those applicable to section 1034, except that—

"(A) no ownership requirement shall be imposed, and

"(B) the period for which a dwelling is treated as the principal residence of the taxpayer shall include the 30-day period ending on the first day on which it would (but for this subparagraph) be treated as his principal residence.

"(d) SPECIAL RULES.—For purposes of this section—

"(1) DOLLAR AMOUNTS IN CASE OF JOINT OCCUPANCY.—In the case of any dwelling unit which is jointly occupied and used during any calendar year as a principal residence by 2 or more individuals—

"(A) the amount of the credit allowable under subsection (a) by reason of energy conservation expenditures or by reason of solar and wind energy expenditures (as the case may be) made during such calerdar year by any of such individuals with respect to such dwelling unit shall be determined by treating all of such individuals as one taxpayer whose taxable year is such calendar year; and

"(B) each of such individuals shall be allowed a credit under subsection (a) for the taxable year in which such calendar year ends (subject to the limitation of paragraphs (4) and (5) of subsection (b)) in an amount which bears the same ratio to the amount determined under subparagraph (A) as the amount of such expenditures made by such individual during such calendar year bears to the aggregate of such expenditures made by all of such individuals during such calendar year.

"(2) TENANT-STOCKHOLDER IN COOPERATIVE HOUSING CORPORATION.—In the case of an individual who holds stock as a tenant-stockholder (as defined in section 216) in a cooperative housing corporation (as defined in such section), such individual shall be treated as having made his tenant-stockholder's proportionate share (as defined in section 216(b)(3)) of any expenditures of such corporation.

"(3) CONDOMINIUMS.—

"(A) IN GENERAL.—In the case of an individual who is a member of a condominium management association with respect to a condominium which he owns, such individual shall be treated as having made his proportionate share of any expenditures of such association.

"(B) CONDOMINIUM MANAGEMENT ASSOCIATION.—For purposes of this paragraph, the term 'condominium management association' means an organization which meets the requirements of paragraph (1) of section 528(c) (other than subparagraph (E) thereof) with respect to a condominium project substantially all of the units of which are used as residences.

"(e) BASIS ADJUSTMENTS.—For purposes of this subtitle, if a credit is allowed under this section for any expenditure with respect to any property, the increase in the basis of such property which would (but for this subsection) result from such expenditure shall be reduced by the amount of the credit so allowed.

"(f) TERMINATION.—This section shall not apply to expenditures made after December 31, 1984."

(b) TECHNICAL AND CLERICAL AMENDMENTS.—

(1) The table of sections for subpart A of part IV of subchapter A of chapter 1 is amended by inserting after the item relating to section 44B the following new item:

"Sec. 44C. Residential energy credit."

(2) Subsection (c) of section 56 (defining regular tax deduction) is amended by striking out "credits allowable under—" and all that follows and inserting

in lieu thereof "credits allowable under subpart A of part IV other than under sections 31, 39, and 43."

(3) Subsection (a) of section 1016 (relating to adjustments to basis) is amended by inserting after paragraph (20) the following new paragraph:

"(21) to the extent provided in section 44C(e), in the case of property with respect to which a credit has been allowed under section 44C;".

(4) Subsection (b) of section 6096 (relating to designation of income tax payment to Presidential Election Campaign Fund) is amended by striking out "and 44B" and inserting in lieu thereof "44B, and 44C".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years ending on or after April 20, 1977.

PART II—TRANSPORTATION

Subpart A—Gas Guzzler Tax

SEC. 2021. GAS GUZZLER TAX.

(a) GENERAL RULE.—Part I of subchapter A of chapter 32 (relating to motor vehicle excise taxes) is amended by adding at the end thereof the following new section:

"SEC. 4064. GAS GUZZLER TAX.

"(a) IMPOSITION OF TAX.—There is hereby imposed on the sale by the manufacturer of each automobile a tax determined in accordance with the following tables:

"(1) In the case of a 1979 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 15	0
At least 14 but less than 15	$339
At least 13 but less than 14	438
Less than 13	553

"(2) In the case of a 1980 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 17	0
At least 16 but less than 17	$249
At least 15 but less than 16	333
At least 14 but less than 15	428
At least 13 but less than 14	538
Less than 13	666

"(3) In the case of a 1981 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 18.5	0
At least 17.5 but less than 18.5	$245
At least 16.5 but less than 17.5	341
At least 15.5 but less than 16.5	458
At least 14.5 but less than 15.5	597
At least 13.5 but less than 14.5	764
At least 12.5 but less than 13.5	968
Less than 12.5	1,216

"(4) In the case of a 1982 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 20	0
At least 19 but less than 20	$266
At least 18 but less than 19	369
At least 17 but less than 18	491
At least 16 but less than 17	636
At least 15 but less than 16	809
At least 14 but less than 15	1,015
At least 13 but less than 14	1,264
Less than 13	1,565

"(5) In the case of a 1983 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 20.5	0
At least 19.5 but less than 20.5	$345
At least 18.5 but less than 19.5	459
At least 17.5 but less than 18.5	593
At least 16.5 but less than 17.5	751
At least 15.5 but less than 16.5	938
At least 14.5 but less than 15.5	1,161
At least 13.5 but less than 14.5	1,427
At least 12.5 but less than 13.5	1,747
Less than 12.5	2,134

"(6) In the case of a 1984 model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 22	0
At least 21 but less than 22	$371
At least 20 but less than 21	490
At least 19 but less than 20	631
At least 18 but less than 19	797
At least 17 but less than 18	990
At least 16 but less than 17	1,218
At least 15 but less than 16	1,486
At least 14 but less than 15	1,804
At least 13 but less than 14	2,183
Less than 13	2,638

"(7) In the case of a 1985 or later model year automobile:

"If the fuel economy of the model type in which the automobile falls is:	The tax is:
At least 23.5	0
At least 22.5 but less than 23.5	$397
At least 21.5 but less than 22.5	524
At least 20.5 but less than 21.5	671
At least 19.5 but less than 20.5	843
At least 18.5 but less than 19.5	1,043
At least 17.5 but less than 18.5	1,276
At least 16.5 but less than 17.5	1,550
At least 15.5 but less than 16.5	1,868
At least 14.5 but less than 15.5	2,244
At least 13.5 but less than 14.5	2,688
At least 12.5 but less than 13.5	3,219
Less than 12.5	3,856

"(b) DEFINITIONS.—For purposes of this section—

"(1) AUTOMOBILE.—The term 'automobile' means any 4-wheeled vehicle propelled by fuel—

"(A) which is manufactured primarily for use on public streets, roads, and highways (except any vehicle operated exclusively on a rail or rails), and

"(B) which is rated at 6,000 pounds gross vehicle weight or less.

Such term does not include a truck designed primarily to carry property and the cargo capacity of which is at least 1,000 pounds.

"(2) FUEL ECONOMY.—The term 'fuel economy' means the average number of miles traveled by an automobile per gallon of gasoline (or equivalent amount of other fuel) consumed, as determined by the EPA Administrator in accordance with procedures established under subsection (c).

"(3) MODEL TYPE.—The term 'model type' means a particular class of automobile as determined by regulation by the EPA Administrator.

"(4) MODEL YEAR.—The term 'model year', with reference to any specific calendar year, means a manufacturer's annual production period (as determined by the EPA Administrator) which includes January 1 of such calendar year. If a manufacturer has no annual production period, the term 'model year' means the calendar year.

"(5) MANUFACTURER.—The term 'manufacturer' includes a producer or importer.

"(6) EPA ADMINISTRATOR.—The term 'EPA Administrator' means the Administrator of the Environmental Protection Agency.

"(7) FUEL.—The term 'fuel' means gasoline and diesel fuel. The Secretary (after consultation with the Secretary of Transportation) may, by regulation, include any product of petroleum or natural gas within the meaning of such term if he determines that such inclusion is consistent with the need of the Nation to conserve energy.

"(c) DETERMINATION OF FUEL ECONOMY.—For purposes of this section—

"(1) IN GENERAL.—Fuel economy for any model type shall be measured in accordance with testing and calculation procedures established by the EPA Administrator by regulation. Procedures so established shall be the procedures utilized by the EPA Administrator for model year 1975 (weighted 55 percent urban cycle, and 45 percent highway cycle), or procedures which yield comparable results. Procedures under this subsection, to the extent practicable, shall require that fuel economy tests be conducted in conjunction with emissions tests conducted under section 206 of the Clean Air Act. The EPA Administrator shall report any measurements of fuel economy to the Secretary.

"(2) SPECIAL RULE FOR FUELS OTHER THAN GASOLINE.—The EPA Administrator shall by regulation determine that quantity of any other fuel which is the equivalent of one gallon of gasoline.

"(3) TIME BY WHICH REGULATIONS MUST BE ISSUED.—Testing and calculation procedures applicable to a model year, and any amendment to such procedures (other than a technical or clerical amendment), shall be promulgated not less than 12 months before the model year to which such procedures apply."

(b) REDUCTION IN BASIS OF AUTOMOBILE ON WHICH GAS GUZZLER TAX WAS IMPOSED.—Section 1016 (relating to adjustments to basis) is amended by redesignating subsection (c) as subsection (d) and by inserting after subsection (b) the following new subsection:

"(c) REDUCTION IN BASIS OF AUTOMOBILE ON WHICH GAS GUZZLER TAX WAS IMPOSED.—If—

"(1) the taxpayer acquires any automobile with respect to which a tax was imposed by section 4064, and

"(2) the use of such automobile by the taxpayer begins not more than 1 year after the date of the first sale for ultimate use of such automobile,

the basis of such automobile shall be reduced by the amount of the tax imposed by section 4064 with respect to such automobile. In the case of importation, if the date of entry or withdrawal from warehouse for consumption is later than the date of the first sale for ultimate use, such later date shall be substituted for the date of such first sale in the preceding sentence."

(c) DENIAL OF CERTAIN EXEMPTIONS AND REFUNDS.—

(1) TAX-FREE SALES.—Subsection (a) of section 4221 (relating to certain tax-free sales) is amended by adding at the end thereof the following new sentence: "Paragraphs (4) and (5) shall not apply to the tax imposed by section 4064."

(2) UNITED STATES AND POSSESSIONS.—Section 4293 (relating to exemption for United States and possessions) is amended by inserting "(other than section 4064)" after "chapters 31 and 32".

(3) DENIAL OF REFUNDS FOR CERTAIN USES.—Paragraph (2) of section 6416(b) (relating to tax payments considered overpayments in the case of specified uses and resales) is amended by adding at the end thereof the following new sentence:

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"Subparagraphs (C) and (D) shall not apply in the case of any tax paid under section 4064."

(d) PAYMENT OF TAX IN CASE OF LEASED AUTOMOBILES.—Section 4217 (relating to leases) is amended by adding at the end thereof the following new subsection:

"(e) LEASES OF AUTOMOBILES SUBJECT TO GAS GUZZLER TAX.—

"(1) IN GENERAL.—In the case of the lease of an automobile the sale of which by the manufacturer would be taxable under section 4064, the foregoing provisions of this section shall not apply, but, for purposes of this chapter—

"(A) the first lease of such automobile by the manufacturer shall be considered to be a sale, and

"(B) any lease of such automobile by the manufacturer after the first lease of such automobile shall not be considered to be a sale.

"(2) PAYMENT OF TAX.—In the case of a lease described in paragraph (1)(A)—

"(A) there shall be paid by the manufacturer on each lease payment that portion of the total gas guzzler tax which bears the same ratio to such total gas guzzler tax as such payment bears to the total amount to be paid under such lease, "(B) if such lease is canceled, or the automobile is sold or otherwise disposed of, before the total gas guzzler tax is payable, there shall be paid by the manufacturer on such cancellation, sale, or disposition the difference between the tax imposed under subparagraph (A) on the lease payments and the total gas guzzler tax, and

"(C) if the automobile is sold or otherwise disposed of after the total gas guzzler tax is payable, no tax shall be imposed under section 4064 on such sale or disposition.

"(3) DEFINITIONS.—For purposes of this subsection—

"(A) MANUFACTURER.—The term 'manufacturer' includes a producer or importer.

"(B) TOTAL GAS GUZZLER TAX.—The term 'total gas guzzler tax' means the tax imposed by section 4064, computed at the rate in effect on the date of the first lease."

(e) CLERICAL AMENDMENT.—The table of sections for part I of subchapter A of chapter 32 is amended by adding at the end thereof the following new item:

"Sec. 4064. Gas guzzler tax."

(f) EFFECTIVE DATE.—The amendments made by this section shall apply with respect to 1979 and later model year automobiles (as defined in section 4064(b) of the Internal Revenue Code of 1954).

SEC. 2022. TRUST FUND FOR PURPOSE OF REDUCING PUBLIC DEBT.

(a) ESTABLISHMENT OF TRUST FUND.—There is hereby established in the Treasury of the United States a trust fund to be known as the "Public Debt Retirement Trust Fund" (hereinafter in this section referred to as the "Trust Fund"). The Trust Fund shall consist of such amounts as may be appropriated and transferred to it as provided in subsection (b).

(b) TRANSFER OF GAS GUZZLER TAX TO THE TRUST FUND.—

(1) IN GENERAL.—There is hereby appropriated to the Trust Fund, out of any money in the Treasury not otherwise appropriated, amounts equivalent to the taxes which are imposed by section 4064 of the Internal Revenue Code of 1954 (relating to gas guzzler tax) and which are received in the Treasury.

(2) METHOD OF TRANSFER.—The amounts appropriated by paragraph (1) shall be transferred at least monthly from the general fund of the Treasury to the Trust Fund on the basis of estimates by the Secretary of the Treasury of amounts referred to in such paragraph received in the Treasury. Proper adjustments

shall be made in the amounts subsequently transferred to the extent prior estimates were in excess of or less than amounts required to be transferred.

(c) USE OF TRUST FUND.—Amounts in the Trust Fund may be used only for the payment at maturity, or the redemption or purchase before maturity, of any of the obligations of the United States included in the public debt of the United States. All obligations of the United States paid, redeemed, or purchased with money out of the Trust Fund shall be canceled and retired and shall not be reissued.

Subpart B—Motor Fuels

SEC. 2023. REPEAL OF DEDUCTION FOR STATE AND LOCAL TAXES ON GASOLINE AND OTHER MOTOR FUELS.

(a) REPEAL.—Paragraph (5) of section 164 (a) (relating to deduction for taxes) is hereby repealed.

(b) CONFORMING AMENDMENTS.—

(1) The heading of paragraph (5) of section 164 (b) is amended by striking out "AND GASOLINE TAXES".

(2) The text of such paragraph (5) is amended by striking out "or of any tax on the sale of gasoline, diesel fuel, or other motor fuel".

(c) EFFECTIVE DATE.—The amendments made by this section shall take effect at the close of December 31, 1977.

SEC. 2024. EXTENSION TO 1985 OF EXISTING RATE OF TAX ON GASOLINE AND OTHER MOTOR FUELS.

(a) IN GENERAL.—The following provisions are amended by striking out "1979" and inserting in lieu thereof "1985":

(1) Section 4041(e) (relating to rate reduction).

(2) Section 4081(b) (relating to imposition of tax on gasoline).

(3) Section 6421(h) (relating to tax on gasoline used for certain nonhighway purposes or by local transit systems).

(b) TECHNICAL AMENDMENTS.—

(1) Paragraph (3) of section 4041(c) (relating to rate of tax) is amended to read as follows:

"(3) RATE OF TAX.—The rate of tax imposed by paragraph (2) is 3 cents a gallon."

(2) Subsection (a) of section 6412 (relating to floor stocks refunds) is amended by adding at the end thereof the following new paragraph:

"(3) EXTENSION OF TAX ON GASOLINE.—In the case of gasoline subject to the tax imposed by section 4081, paragraph (1) shall be applied—

"(A) by substituting '1985' for '1979' each place it appears, and

"(B) by substituting '1986' for '1980' each place it appears."

SEC. 2025. AMENDMENT OF MOTORBOAT FUEL PROVISIONS.

(a) 2-CENT INCREASE IN TAX ON MOTORBOAT FUEL.—

(1) The second sentence of section 4041(b) (relating to tax on special motor fuels) is amended by striking out "the tax imposed" and inserting in lieu thereof "and otherwise than as a fuel in a motorboat, the tax imposed".

(2) The third sentence of section 4041(b) is amended by striking out "a tax of 2 cents a gallon" and inserting in lieu thereof "or is used as a fuel in a motorboat, a tax of 2 cents a gallon".

(b) REFUND OF GASOLINE USED FOR CERTAIN NONHIGHWAY PURPOSES.—The first sentence of section 6421(a) (relating to nonhighway uses) is amended by striking out "the Secretary" and inserting in lieu thereof "and otherwise than as a fuel in a motorboat, the Secretary".

(c) LAND AND WATER CONSERVATION FUND.—Paragraph (1) of section 201(b) of the Land and Water Conservation Fund Act of 1965 is amended—

(1) by striking out "1980" and inserting in lieu thereof "1978", and

(2) by striking out "1979" and inserting in lieu thereof "1977".

(d) EFFECTIVE DATE.—The amendments made by this section shall take effect on October 1, 1977.

Subpart C—Provisions Related to Buses

SEC. 2026. REMOVAL OF EXCISE TAX ON BUSES.

(a) GENERAL RULE.—Paragraph (6) of section 4063 (a) (relating to exemption for local transit buses) is amended to read as follows:

"(6) BUSES.—The tax imposed under section 4061 (a) shall not apply in the case of any automobile bus chassis or automobile bus body."

(b) FLOOR STOCK REFUNDS.—

(1) IN GENERAL.—Where, before the day after the date of the enactment of this Act, any tax-repealed article (as defined in subsection (e)) has been sold by the manufacturer, producer, or importer and on such day is held by a dealer and has not been used and is intended for sale, there shall be credited or refunded (without interest) to the manufacturer, producer, or importer an amount equal to the tax paid by such manufacturer, producer, or importer on his sale of the article, if—

(A) claim for such credit or refund is filed with the Secretary of the Treasury before the first day of the 10th calendar month beginning after the day after the date of the enactment of this Act based upon a request submitted to the manufacturer, producer, or importer before the first day of the 7th calendar month beginning after the day after the date of the enactment of this Act by the dealer who held the article in respect of which the credit or refund is claimed; and

(B) on or before the first day of such 10th calendar month reimbursement has been made to the dealer by the manufacturer, producer, or importer in an amount equal to the tax paid on the article or written consent has been obtained from the dealer to allowance of the credit or refund.

(2) LIMITATION ON ELIGIBILITY FOR CREDIT OR REFUND.—No manufacturer, producer, or importer shall be entitled to credit or refund under paragraph (1) unless he has in his possession such evidence of the inventories with respect to which the credit or refund is claimed as may be required by regulations prescribed by the Secretary of the Treasury under this subsection.

(3) OTHER LAWS APPLICABLE.—All provisions of law, including penalties, applicable with respect to the taxes imposed by section 4061 (a) of the Internal Revenue Code of 1954 shall, insofar as applicable and

not inconsistent with paragraphs (1) and (2) of this subsection, apply in respect of the credits and refunds provided for in paragraph (1) to the same extent as if the credits or refunds constituted overpayments of the tax.

(o) REFUNDS WITH RESPECT TO CERTAIN CONSUMER PURCHASES.—

(1) IN GENERAL.—Except as otherwise provided in paragraph (2), where on or after April 20, 1977, and on or before the date of the enactment of this Act, a tax-repealed article (as defined in subsection (e)) has been sold to an ultimate purchaser, there shall be credited or refunded (without interest) to the manufacturer, producer, or importer of such article an amount equal to the tax paid by such manufacturer, producer, or importer on his sale of the article.

(2) LIMITATION ON ELIGIBILITY FOR CREDIT OR REFUND.—No manufacturer, producer, or importer shall be entitled to a credit or refund under paragraph (1) with respect to an article unless—

(A) he has in his possession such evidence of the sale of the article to an ultimate purchaser, and of the reimbursement of the tax to such purchaser, as may be required by regulation prescribed by the Secretary of the Treasury under this subsection;

(B) claim for such credit or refund is filed with the Secretary of the Treasury before the first day of the 10th calendar month beginning after the day after the date of the enactment of this Act based upon information submitted to the manufacturer, producer, or importer before the first day of the 7th calendar month beginning after the day after the date of the enactment of this Act by the person who sold the article (in respect of which the credit or refund is claimed) to the ultimate purchaser; and

(C) on or before the first day of such 10th calendar month reimbursement has been made to the ultimate purchaser in an amount equal to the tax paid on the article.

(3) OTHER LAWS APPLICABLE.—All provisions of law, including penalties, applicable with respect to the taxes imposed by section 4061 (a) of such Code shall, insofar as applicable and not inconsistent with paragraph (1) or (2) of this subsection, apply in respect of the credits and refunds provided for in paragraph (1) to the same extent as if the credits or refunds constituted overpayments of the tax.

(d) CERTAIN USES BY MANUFACTURER, ETC.—Any tax paid by reason of section 4218 (a) of such Code (relating to use by manufacturer or importer considered sale) on any tax-repealed article shall be deemed an overpayment of such tax if the tax was imposed on such article by reason of such section 4218 (a) on or after April 20, 1977.

(e) DEFINITIONS.—For purposes of this section—

(1) The term "dealer" includes a wholesaler, jobber, distributor, or retailer.

(2) An article shall be considered as "held by a dealer" if title thereto has passed to such dealer (whether or not delivery to him has been made) and if, for purposes of consumption, title to such article or possession thereof has not at any time been transferred to any person other than a dealer.

(3) The term "tax-repealed article" means an article on which a tax was imposed by section 4061 (a) of such Code (as in effect on the day before the date of the enactment of this Act) and which is exempted from such tax by paragraph (6) of section 4063 (a) of such Code (as amended by subsection (a) of this section).

(f) TECHNICAL AND CONFORMING AMENDMENTS.—

(1) The heading for paragraph (1) of section 6412 (a) (relating to floor stocks refunds) is amended by striking out "AND BUSES".

(2) Subsection (d) of section 4222 (relating to registration in case of certain other exemptions) is

amended by striking out "4063 (a) (6) or (7)" and inserting in lieu thereof "4063 (a) (7)".

(g) EFFECTIVE DATE.—

(1) The amendments made by this section shall apply with respect to articles sold on or after April 20, 1977.

(2) For purposes of paragraph (1), an article shall not be considered sold before April 20, 1977, unless possession or right to possession passes to the purchaser before such day.

(3) In the case of—

(A) a lease,

(B) a contract for the sale of an article where it is provided that the price shall be paid by installments and title to the article sold does not pass until a future date notwithstanding partial payment by installments,

(C) a conditional sale, or

(D) a chattel mortgage arrangement wherein it is provided that the sale price shall be paid in installments,

entered into before April 20, 1977, payments made on or after such date with respect to the article leased or sold shall, for purposes of this subsection, be considered as payments made with respect to an article sold on or after such date, if the lessor or vendor establishes that the amount of payments payable on or after such date with respect to such article has been reduced by an amount equal to that portion of the tax applicable with respect to the lease or sale of such article which is due and payable on or after such date. If the lessor or vendor does not establish that the payments have been so reduced, they shall be treated as payments made in respect of an article sold before April 20, 1977.

SEC. 2027. REMOVAL OF EXCISE TAX ON BUS PARTS.

(a) EXEMPT SALES.—Subsection (e) of section 4221 (relating to special rules for certain tax-free sales) is amended by adding at the end thereof the following new paragraph:

"(6) BUS PARTS AND ACCESSORIES.—Under regulations prescribed by the Secretary, the tax imposed by section 4061 (b) shall not apply to any part or accessory which is sold for use by the purchaser on or in connection with an automobile bus."

(b) REFUND FOR CERTAIN SALES OF BUS PARTS.—Subparagraph (I) of section 6416 (b) (2) (relating to refund for specified uses and resales) is amended to read as follows:

"(I) in the case of any article taxable under section 4061 (b), sold for use by the purchaser on or in connection with an automobile bus;".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to sales on or after the first day of the first calendar month beginning more than 10 days after the date of the enactment of this Act.

SEC. 2028. REMOVAL OF EXCISE TAX ON CERTAIN ITEMS USED IN CONNECTION WITH INTERCITY, LOCAL, AND SCHOOL BUSES.

(a) TIRES, TUBES, AND TREAD RUBBER.—

(1) IN GENERAL.—Paragraph (5) of section 4221 (e) (relating to school buses) is amended to read as follows:

"(5) TIRES, TUBES, AND TREAD RUBBER USED ON INTERCITY, LOCAL, AND SCHOOL BUSES.—Under regulations prescribed by the Secretary—

"(A) the taxes imposed by paragraphs (1) and (3) of section 4071 (a) shall not apply in the case of tires or inner tubes for tires sold for use by the purchaser on or in connection with a qualified bus, and

"(B) the tax imposed by paragraph (4) of section 4071 (a) shall not apply in the case of tread rubber sold for use by the purchaser in the recapping or retreading of any tire to be used by the purchaser on or in connection with a qualified bus."

(2) QUALIFIED BUS DEFINED.—Subsection (d) of section 4221 (relating to definitions) is amended by adding at the end thereof the following new paragraph:

"(7) QUALIFIED BUS.—

"(A) IN GENERAL.—The term 'qualified bus' means—

"(i) an intercity or local bus, and

"(ii) a school bus.

"(B) INTERCITY OR LOCAL BUS.—The term 'intercity or local bus' means any automobile bus which is used predominantly in furnishing (for compensation) passenger land transportation available to the general public if—

"(i) such transportation is scheduled and along regular routes, or

"(ii) the passenger seating capacity of such bus is at least 20 adults (not including the driver).

"(C) SCHOOL BUS.—The term 'school bus' means any automobile bus substantially all the use of which is in transporting students and employees of schools. For purposes of the preceding sentence, the term 'school' means an educational organization which normally maintains a regular faculty and curriculum and normally has a regularly enrolled body of pupils or students in attendance at the place where its educational activities are carried on."

(3) TECHNICAL AMENDMENT.—Paragraph (2) of section 6416(b) (relating to specified uses and resales) is amended by striking out the period at the end of subparagraph (K) and inserting in lieu thereof a semicolon and by inserting after subparagraph (K) the following new subparagraphs:

"(L) in the case of any tire or inner tube taxable under paragraph (1) or (3) of section 4071(a), sold to any person for use as described in section 4221(e)(5)(A); or

"(M) in the case of tread rubber taxable under paragraph (4) of section 4071(a), used in the recapping or retreading of a tire sold to any person for use on or in connection with a qualified bus (as defined in section 4221(d)(7))."

(b) REPAYMENT OF TAX ON LUBRICATING OIL USED IN INTERCITY, LOCAL, OR SCHOOL BUSES.—

(1) IN GENERAL.—Subsection (a) of section 6424 (relating to lubricating oil not used in highway motor vehicles) is amended to read as follows:

"(a) PAYMENTS.—Except as provided in subsection (f), if lubricating oil (other than cutting oils, as defined in section 4092(b), and other than oil which has previously been used) is used—

"(1) otherwise than in a highway motor vehicle, or

"(2) in a qualified bus (as defined in section 4221(d)(7)),

the Secretary shall pay (without interest) to the ultimate purchaser of such lubricating oil an amount equal to 6 cents for each gallon of lubricating oil so used."

(2) TECHNICAL AND CONFORMING AMENDMENTS.—

(A) The section heading for section 6424 is amended by striking out "NOT USED IN HIGHWAY MOTOR VEHICLES" and inserting in lieu thereof "USED FOR CERTAIN NONTAXABLE PURPOSES".

(B) The table of sections for subchapter B of chapter 65 (relating to rules of special application) is amended by striking out "not used in highway motor vehicles" in the item relating to section 6424 and inserting in lieu thereof "used for certain nontaxable purposes".

(C) Paragraph (3) of section 39(a) (relating to certain uses of gasoline, special fuels, and lubricating oil) is amended by striking out "otherwise than in a highway motor vehicle" and inserting in lieu thereof "for certain nontaxable purposes".

(D) Section 6504 (9) and 6675 (a) are each amended by striking out "not used in highway motor vehicles" and inserting in lieu thereof "used for certain nontaxable purposes".

(E) Paragraph (3) of section 209 (f) of the Highway Revenue Act of 1956 is amended by striking out "lubricating oil not used in highway motor vehicles" and inserting in lieu thereof "lubricating oil used for certain nontaxable purposes".

(c) REPAYMENT OF TAX ON FUELS USED BY PUBLIC TRANSIT BUSES OR SCHOOL BUSES.—

(1) GASOLINE.—Subsection (b) of section 6421 (relating to local transit systems) is amended to read as follows:

"(b) INTERCITY, LOCAL, OR SCHOOL BUSES.—

"(1) ALLOWANCE.—Except as provided in paragraph (2) and subsection (i), if gasoline is used in an automobile bus while engaged in—

"(A) furnishing (for compensation) passenger land transportation available to the general public, or

"(B) the transportation of students and employees of schools (as defined in the last sentence of section 4221 (d) (7) (C)), the Secretary shall pay (without interest) to the ultimate purchaser of such gasoline an amount equal to the product of the number of gallons of gasoline so used multiplied by the rate at which tax was imposed on such gasoline by section 4081.

"(2) LIMITATION IN CASE OF NONSCHEDULED INTERCITY OR LOCAL BUSES.—Paragraph (1) (A) shall not apply in respect of gasoline used in any automobile bus while engaged in furnishing transportation which is not scheduled and not along regular routes unless the seating capacity of such bus is at least 20 adults (not including the driver)."

(2) OTHER FUELS.—Subsection (b) of section 6427 (relating to local transit systems) is amended to read as follows:

"(b) INTERCITY, LOCAL, OR SCHOOL BUSES.—

"(1) ALLOWANCE.—Except as provided in paragraph (2) and subsection (g), if any fuel on the sale of which tax was imposed by subsection (a) or (b) of section 4041 is used in an automobile bus while engaged in—

"(A) furnishing (for compensation) passenger land transportation available to the general public, or

"(B) the transportation of students and employees of schools (as defined in the last sentence of section 4221 (d) (7) (C)),

the Secretary shall pay (without interest) to the ultimate purchaser of such fuel an amount equal to the product of the number of gallons of such fuel so used multiplied by the rate at which tax was imposed on such fuel by subsection (a) or (b) of section 4041.

"(2) LIMITATION IN CASE OF NONSCHEDULED INTERCITY OR LOCAL BUSES.—Paragraph (1) (A) shall not apply in respect of fuel used in any automobile bus while engaged in furnishing transportation which is not scheduled and not along regular routes unless the seating capacity of such bus is at least 20 adults (not including the driver)."

(3) TECHNICAL AMENDMENTS.—

(A) Subsection (d) of section 6421 is amended to read as follows:

"(d) GASOLINE DEFINED.—For purposes of this section, the term 'gasoline' has the meaning given to such term by section 4082 (b)."

(B) Subsection (c) of section 4483 is amended by inserting "(as in effect on the day before the date of the enactment of the Energy Tax Act of 1977)" after "section 6421 (b) (2)".

(d) EFFECTIVE DATE.—The amendments made by this section shall take effect on the first day of the first calendar month which begins more than 10 days after the date of the enactment of this Act.

Subpart D—Credit for Electric Motor Vehicles

SEC. 2029. CREDIT FOR QUALIFIED ELECTRIC MOTOR VEHICLES.

(a) GENERAL RULE.—Subpart A of part IV of subchapter A of chapter 1 (relating to credits allowable) is amended by inserting after section 44C the following new section:

"SEC. 44D. QUALIFIED ELECTRIC MOTOR VEHICLES.

"(a) GENERAL RULE.—In the case of an individual, there shall be allowed as a credit against the tax imposed by this chapter for the taxable year an amount equal to the cost to the taxpayer to acquire a qualified electric motor vehicle during the taxable year, to the extent that such cost does not exceed $300.

"(b) LIMITATIONS.—

"(1) APPLICATION WITH OTHER CREDITS.—The credit allowed by subsection (a) shall not exceed the tax imposed by this chapter for the taxable year, reduced by the sum of the credits allowable under a section of this part having a lower number or letter designation than this section, other than the credits allowable by sections 31, 39, and 43.

"(2) JOINT ACQUISITION.—If any qualified electric motor vehicle is jointly acquired by 2 or more individuals—

"(A) the aggregate amount allowable as a credit under subsection (a) to such individuals with respect to such vehicle shall not exceed $300, and

"(B) the amount allowable as a credit for the taxable year shall be apportioned among such individuals on the basis of their respective shares of the cost.

"(c) QUALIFIED ELECTRIC MOTOR VEHICLE DEFINED.—For purposes of this section, the term 'qualified electric motor vehicle' means any 4-wheeled vehicle—

"(1) which is manufactured primarily for use on public streets, roads, and highways (except any vehicle operated exclusively on a rail or rails),

"(2) which is powered primarily by an electric motor drawing current from rechargeable storage batteries or other portable sources of electric current,

"(3) which is acquired by the taxpayer on or after April 20, 1977, for the personal use of the taxpayer or a member of his family, and

"(4) the original use of which begins with the taxpayer or a member of his family.

"(d) TERMINATION.—This section shall not apply to any qualified electric motor vehicle acquired after December 31, 1982."

(b) TECHNICAL AND CONFORMING AMENDMENTS.—

(1) The table of sections for such subpart A is amended by inserting after the item relating to section 44C the following new item:

"Sec. 44D. Qualified electric motor vehicles."

(2) Section 6096(b) (relating to designation of income tax payment to Presidential Election Campaign Fund) is amended by striking out "and 44C" and inserting in lieu thereof "44C, and 44D".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to vehicles acquired on or after April 20, 1977, in taxable years ending on or after such date.

PART III—CRUDE OIL EQUALIZATION TAXES

Subpart A—Imposition of Taxes

SEC. 2031. CRUDE OIL EQUALIZATION TAXES.

(a) IN GENERAL.—Subtitle D (relating to excise taxes) is amended by adding at the end thereof the following new chapter:

"CHAPTER 45—ENERGY EXCISE TAXES

"Subchapter A—Crude Oil Equalization Taxes

"SEC. 4986. CRUDE OIL EQUALIZATION TAXES.

"(a) IMPOSITION OF TAX ON CONTROLLED CRUDE OIL.—A tax is hereby imposed on the first purchase—

"(1) during 1978 or 1979, of lower tier crude oil and

"(2) after 1979 and on or before the termination date, of controlled crude oil.

"(b) AMOUNT OF CONTROLLED CRUDE OIL TAX.—The amount per barrel of the tax imposed by subsection (a) is—

"(1) 1978.—In the case of a first purchase of lower tier crude oil of any classification during any calendar month in 1978, one-half the excess (if any) of:

"(i) the ceiling price for such month of upper tier crude oil of the same classification, over

"(ii) the ceiling price for such lower tier crude oil.

"(2) 1979.—In the case of a first purchase of lower tier crude oil of any classification during any calendar month in 1979, the excess (if any) of:

"(i) the ceiling price for such month of upper tier crude oil of the same classification, over

"(ii) the ceiling price for such lower tier crude oil.

"(3) AFTER 1979 AND ON OR BEFORE THE TERMINATION DATE.—In the case of a first purchase of controlled crude oil of any classification during any period after 1979 and on or before the termination date, the excess (if any) of—

"(A) the uncontrolled price for such period of crude oil of the same classification, over

"(B) the controlled price for such controlled crude oil.

"(c) IMPOSITION OF TAX ON NATURAL GAS LIQUIDS.—

"(1) IN GENERAL.—A tax is hereby imposed upon any controlled natural gas liquid—

"(A) sold by any person for use by the purchaser, or

"(B) used by any person unless there was a taxable sale of such liquid under subparagraph (A).

For purposes of this paragraph, the placing by a manufacturer of a liquid in a container having a capacity of 2 gallons or less shall be treated as a use.

"(2) EXEMPTIONS.—No tax shall be imposed under paragraph (1) on any controlled natural gas liquid sold for use or used—

"(A) on a farm for farming purposes (within the meaning of section 6420(c)),

"(B) in an exempt structure (within the meaning of section 6429(b)), or

"(C) as a feedstock in the production of natural gas liquids.

"(d) AMOUNT OF TAX ON NATURAL GAS LIQUIDS.—

"(1) IN GENERAL.—The amount per barrel of the tax imposed by subsection (c) is—

"(A) 1978.—In the case of a taxable sale or use during 1978, $\frac{1}{3}$ of the amount of the price gap.

"(B) 1979.—In the case of a taxable sale or use during 1979, $\frac{2}{3}$ of the amount of the price gap.

"(C) AFTER 1979 AND ON OR BEFORE THE TERMINATION DATE.—In the case of a taxable sale or use after 1979 and on or before the termination date, the amount of the price gap.

"(2) PRICE GAP DEFINED.—For purposes of paragraph (1), the term 'price gap' means, with respect to any taxable sale or use of any natural gas liquid during any calendar month, the excess of—

"(A) the average wholesale price of a barrel of No. 2 distillate oil in the region in which such sale or use occurred (for the most recent calendar month for which data is available) adjusted—

"(i) to reflect differences in energy content between such liquid and No. 2 distillate oil, and

"(ii) to reflect seasonal price differences between the month for which data is available and the month in which the sale or use occurred, over

"(B) the controlled price for a barrel of such natural gas liquid.

"(e) TERMINATION DATE.—For purposes of this subchapter, the termination date is September 30, 1981.

"SEC. 4987. RULES RELATING TO APPLICATION OF SECTION 4986.

"(a) LIABILITY AND COLLECTION OF TAX ON CRUDE OIL.—

"(1) FIRST PURCHASER LIABLE FOR TAX.—The first purchaser of the controlled crude oil shall be liable for the tax imposed by section 4986(a) on the first purchase thereof.

"(2) COLLECTION AND PAYMENT OF TAX.—

"(A) IN GENERAL.—Except in the case of a jeopardy assessment, and except as otherwise provided in this subsection, the tax imposed by section 4986 (a) shall be due and payable on the first day of the 4th calendar month following the month of the first purchase.

"(B) COLLECTION OF TAX IN CERTAIN CASES.—The Secretary may by regulations provide for the collection from a subsequent purchaser, user, or exporter of the tax imposed by section 4986 (a) on the first purchaser—

"(i) where the first purchaser is not a United States person and is not engaged in a trade or business in the United States, and

"(ii) in any other case where there is substantial likelihood that such tax will not be paid.

"(b) LIABILITY AND COLLECTION OF TAX ON NATURAL GAS LIQUIDS.—The tax imposed by section 4986 (c)—

"(1) on any sale shall be paid by the purchaser and collected by the seller at the time of the sale, or

"(2) on any use shall be paid by the user,

and shall be due and payable on the 15th day of the second month following the month in which such sale or use occurred.

"(c) CREDIT OR REFUND OF CRUDE OIL TAX WHERE CRUDE OIL IS USED TO PRODUCE NATURAL GAS LIQUIDS.—

"(1) IN GENERAL.—If any natural gas liquid is produced in the United States by a refiner from crude oil, the amount determined under paragraph (3)—

"(A) shall be allowed as a credit against any tax which is imposed by section 4986(a) for which the refiner is liable, and

"(B) to the extent not allowed as a credit under subparagraph (A), shall be paid by the Secretary to the refiner at such times (not less frequently than once each calendar quarter) as the Secretary may by regulations prescribe.

"(2) CREDIT OR PAYMENT MUST BE PASSED ON.—No credit or payment shall be allowed or made under paragraph (1) unless the refiner furnishes such evidence as may be prescribed by the Secretary by regulations that the price of the natural gas liquid has not been increased to reflect any portion of the tax imposed by section 4986(a) for which credit or payment is claimed.

"(3) AMOUNT OF CREDIT OR PAYMENT.—The amount determined under this paragraph for any refiner for any period is the number of barrels of petroleum products produced by the refiner during such period multiplied by the amount determined—

"(A) by multiplying 42 times the amount per gallon determined under section 6429(c) for the calendar year in which such period occurs, by

"(B) a fraction—

"(i) the numerator of which is the aggregate Btu of natural gas liquids produced by the refiner from crude oil during such period, and

"(ii) the denominator of which is the aggregate Btu of all petroleum products produced by the refiner from crude oil during such period.

"(4) APPLICABLE LAWS.—

"(A) IN GENERAL.—All provisions of law, including penalties, applicable in respect of the tax imposed by section 4986(a) shall, insofar as applicable and not inconsistent with this subsection, apply in respect of the payments provided for in paragraph (1)(B) to the same extent as if such payments constituted refunds of overpayments of the tax so imposed.

"(B) EXAMINATION OF BOOKS AND WITNESSES.—For the purpose of ascertaining the correctness of any claim made under this subsection, or the correctness of any payment made in respect to any such claim, the Secretary shall have the authority granted by paragraphs (1), (2), and (3) of section 7602 (relating to examination of books and witnesses) as if the claimant were the person liable for the tax.

"(d) AUTHORITY OF PRESIDENT TO SUSPEND INCREASES IN TAX.—

"(1) GRANT OF AUTHORITY.—If the President determines—

"(A) that, by reason of a significant increase in the world price of oil, there has been or will be an increase in any tax imposed by section 4986, and

"(B) that such increase in tax will have a significant adverse effect on the economy of the United States,

he may submit to the Congress a suspension plan providing for the suspension of part or all of such increase in tax for the period specified in such plan. Such period may not begin before the date on which the plan takes effect and may not exceed 1 year in the case of any 1 plan.

"(2) PLAN MUST STATE CIRCUMSTANCE.—Any plan submitted under paragraph (1) shall set forth the circumstances leading to the submission of the plan and the considerations which the President took into account in formulating the scope and duration of the plan.

"(3) METHOD OF SUSPENSION.—Any plan submitted under paragraph (1) shall provide for the suspension by placing a cap on the increase (or prospective increase) in the price or cost which would (but for such suspension plan) be taken into account—

"(A) under section 4986(b)(3)(A), in the case of crude oil, or

"(B) under section 4986(d)(2)(A), in the case of natural gas liquids.

"(4) TAKING EFFECT OF PLAN. A suspension plan described in paragraph (1) shall take effect only if—

"(A) such plan is submitted to the Congress in accordance with section 2081(a) of the Energy Tax Act of 1977, and

"(B) before the close of the 15th day (as defined in section 2081(c)(5) of such Act) after the day on which such plan is delivered to the Congress, neither the House of Representatives nor the Senate disapproves such plan in accordance with the procedures set forth in section 2081 (b) of the Energy Tax Act of 1977.

"SEC. 4988. DEFINITIONS AND SPECIAL RULES.

"(a) ITEMS SUBJECT TO TAX.—For purposes of this subchapter—

"(1) CRUDE OIL.—The term 'crude oil' means a mixture of hydrocarbons which existed in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Such term includes condensate recovered in associated or nonassociated production by mechanical separators located at any point at or before the inlet side of a gas processing plant.

"(2) NATURAL GAS LIQUIDS.—The term 'natural gas liquids' means a hydrocarbon stream containing, in whole or in substantial part—

"(A) ethane, butane (iso-butane and normal butane), propane, or natural gasoline, or

"(B) a mixture of any substance described in subparagraph (A).

The term does not include crude oil.

"(3) LIQUID.—The term 'liquid' means crude oil or natural gas liquid.

"(4) LOWER TIER CRUDE OIL.—The term 'lower tier crude oil' means controlled crude oil which is certified by the producer as having been sold pursuant to the lower tier ceiling price rule in effect (at the time of the first purchase) under section 4 (a) of the Emergency Petroleum Allocation Act of 1973.

"(5) UPPER TIER CRUDE OIL.—The term 'upper tier crude oil' means controlled crude oil which is certified by the producer as having been sold pursuant to the upper tier ceiling price rule in effect (at the time of the first purchase) under section 4 (a) of the Emergency Petroleum Allocation Act of 1973.

"(6) CONTROLLED LIQUID.—

"(A) CRUDE OIL.—Crude oil shall be treated as controlled if such crude oil is subject to a first sale ceiling price under section 4 (a) of the Emergency Petroleum Allocation Act of 1973.

"(B) NATURAL GAS LIQUIDS.—Any natural gas liquid shall be treated as controlled if—

"(i) in the case of a sale for use described in subparagraph (A) of section 4986 (c) (1), such sale is subject to a ceiling price under section 4 (a) of the Emergency Petroleum Allocation Act of 1973, or

"(ii) in the case of a use described in subparagraph (B) of section 4986 (c) (1), such use would be subject to a ceiling price under such section 4 (a) if the user sold such liquid instead of using it.

"(b) TERRITORIAL EXTENT.—

"(1) IN GENERAL.—

"(A) CRUDE OIL.—The tax imposed by section 4986 (a) shall apply only to liquids produced in the United States.

"(B) NATURAL GAS LIQUIDS.—The tax imposed by section 4986 (c) shall only apply to liquids sold or used in the United States.

"(2) UNITED STATES.—For purposes of this subchapter, the term 'United States' means the United States and any possession of the United States (as such terms are defined in section 638).

"(c) FIRST PURCHASE AND FIRST PURCHASER.—For purposes of this subchapter—

"(1) FIRST PURCHASE.—

"(A) IN GENERAL.—The term 'first purchase' means the first transfer for value by the producer or royalty owner.

"(B) USE OF CRUDE OIL BEFORE FIRST PURCHASE.—Where crude oil is refined or otherwise used (or is exported) before its first purchase, the first purchase shall be treated as occurring at the time of removal from the lease or lease storage.

"(2) FIRST PURCHASER.—The term 'first purchaser' means a transferee determined under paragraph (1).

"(3) EXEMPTION FOR CRUDE OIL USED IN EXTRACTION.—The use of crude oil in the extraction of crude oil, natural gas, or natural gas liquids shall not be treated as a first purchase.

"(4) EXEMPTION FOR CERTAIN REFINED PRODUCTS USED IN EXTRACTION.—The transfer of crude oil to a refiner for refining, and the refining of such crude oil, shall not be treated as a first purchase to the extent that—

"(A) such crude oil is transferred by the producer to a refiner for refining, and

"(B) the producer receives in return for such crude oil products refined from crude oil by such refiner which are used by the producer in the extraction of crude oil, natural gas, or natural gas liquids.

"(d) DEFINITIONS RELATING TO PRICE.—For purposes of this subchapter—

"(1) CONTROLLED PRICE.—The term 'controlled price' means—

"(A) with respect to crude oil, the ceiling price applicable to the first sale of such crude oil under section 4(a) of the Emergency Petroleum Allocation Act of 1973, and

"(B) with respect to any natural gas liquid—

"(i) in the case of a sale for use described in subparagraph (A) of section 4986(c)(1), the ceiling price applicable to such sale under section 4(a) of the Emergency Petroleum Allocation Act of 1973, or

"(ii) in the case of a use described in subparagraph (B) of section 4986(c)(1), the ceiling price which would be applicable under such section 4(a) if the user sold such liquid instead of using it.

"(2) UNCONTROLLED PRICE.—The term 'uncontrolled price' means, with respect to any classification of crude oil, the price at which the first sale of crude oil of the such classification would have been made if such first sale had not been subject to a ceiling price.

"(3) NATIONAL AVERAGE REFINER ACQUISITION COST.—The national average refiner acquisition cost of any tier of crude oil for any month means the average cost to refineries in the United States of crude oil of such tier delivered during such month (properly reduced for the amount of any tax imposed by section 4986).

"(4) CLASSIFICATION.—The Secretary shall establish classifications for crude oil which are based on grade, type, and location and which are designed to avoid undue financial hardship or benefits to producers or first purchasers.

"(5) DETERMINATIONS OF PRICE, ETC.—All determinations of price, cost, and classification necessary to the application of this subchapter shall be made by the Secretary (after consultation with the Secretary of Energy) on the basis of the best available information. Such determinations shall be made not less frequently than once each calendar quarter (or once each calendar month, in the case of natural gas liquids). Such determinations shall be made under procedures established by the Secretary by regulations.

"(e) OTHER DEFINITIONS AND SPECIAL RULES.—For purposes of this subchapter—

"(1) BARREL.—The term 'barrel' means 42 gallons.

"(2) FRACTIONAL BARRELS.—In the case of a fraction of a barrel, the amount of the tax shall be the same fraction of the amount determined under subsection (b) or (d) of section 4986 (whichever applies).

"(3) DETERMINATION OF REGIONS.—The Secretary, after consultation with the Secretary of Energy, shall divide the United States into such regions as may be necessary to carry out the purposes of the tax imposed by section 4986 (c)."

(b) CLERICAL AMENDMENT.—The table of chapters for subtitle D is amended by adding at the end thereof the following:

"CHAPTER 45. Energy excise taxes."

(c) TECHNICAL AMENDMENTS.—

(1) CREDIT OF NATURAL GAS LIQUID TAX MUST BE PASSED ON TO USER.—Subsections (a), (b), and (c) of section 6415 (relating to credits or refunds to persons who collected certain taxes) are each amended by striking out "or 4271" and inserting in lieu thereof "4271, or 4986 (c)".

(2) SEPARATE ACCOUNTING FOR NATURAL GAS LIQUID TAX COLLECTIONS REQUIRED IN CERTAIN CASES.—Section 7512 (relating to separate accounting for certain collected taxes, etc.) is amended—

(A) by striking out "or by chapter 33" each place it appears and inserting in lieu thereof ", chapter 33, or section 4986 (c)", and

(B) by striking out "or chapter 33" each place it appears and inserting in lieu thereof ", chapter 33, or section 4986 (c)".

(3) ADMINISTRATIVE PROVISIONS APPLICABLE TO REFUND OF TAX ON CRUDE OIL USED TO PRODUCE NATURAL GAS LIQUIDS.—

(A) Subsection (a) of section 6675 is amended by inserting "4987 (c) (relating to crude oil used to produce natural gas liquids)," before "6420 (relating to gasoline".

(B) Subsection (b) of section 6675 is amended by striking out "section 6420" and inserting in lieu thereof "section 4987 (c), 6420".

(C) The section heading of section 6675 is amended by striking out "LUBRICATING OIL" and inserting in lieu thereof "LUBRICATING OIL AND WITH RESPECT TO REFUNDS OF CRUDE OIL EQUALIZATION TAXES".

(D) The table of sections for subchapter B of chapter 68 is amended by striking out "lubricating oil" in the item relating to section 6675 and inserting in lieu thereof "lubricating oil and with respect to refunds of crude oil equalization taxes".

(E) Sections 7210, 7603, 7604 (b), 7605, 7609 (c) (1), and 7610 (c) are each amended by striking out "6420 (e) (2)" each place it appears and inserting in lieu thereof "4987 (c) (4) (B), 6420 (e) (2)".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to—

(1) crude oil the first purchase (within the meaning of section 4988(c)(1) of the Internal Revenue Code of 1954) of which occurs after December 31, 1977, and before October 1, 1981, and

(2) sales or uses of natural gas liquids after December 31, 1977, and before October 1, 1981.

SEC. 2032. MISCELLANEOUS PROVISIONS.

(a) STUDY OF SMALL AND INDEPENDENT REFINERS.—

(1) STUDY.—The Secretary of Energy shall conduct a study of the competitive viability of small and independent refiners. Such study shall include an examination of the possible hardships which might be placed on such refiners as a result of the crude oil equalization taxes.

(2) REPORT.—Not later than 90 days after the date of the enactment of this Act, the Secretary of Energy shall submit to the Congress a report on his findings under the study conducted under subsection (a), together with such recommendations for legislation as he determines to be appropriate.

(b) EFFECT OF CRUDE OIL EQUALIZATION TAXES ON CERTAIN NATURAL GAS CONTRACTS.—The taxes imposed by subchapter A of chapter 45 of the Internal Revenue Code of 1954 shall not be taken into account for purposes of determining or redetermining natural gas prices under any contract which was entered into before the date of the enactment of this Act.

Subpart B—Return of Crude Oil Equalization Taxes

SEC. 2033. ESTABLISHMENT OF TRUST FUND FOR THE RETURN OF CRUDE OIL EQUALIZATION TAXES.

(a) CREATION OF TRUST FUND.—There is established in the Treasury of the United States a trust fund to be known as the Crude Oil Equalization Taxes Trust Fund (hereinafter in this section referred to as the "Trust Fund"), consisting of such amounts as may be appropriated to the Trust Fund as provided in subsection (b).

(b) TRANSFER TO TRUST FUND OF NET REVENUES FOR 1978 FROM THE CRUDE OIL EQUALIZATION TAXES.—

(1) IN GENERAL.—There are hereby appropriated to the Trust Fund amounts determined by the Secretary of the Treasury (hereinafter in this section referred to as the "Secretary") to be equivalent to the excess (if any) of—

(A) the amount of the taxes under section 4986 of the Internal Revenue Code of 1954 (relating to crude oil equalization taxes) received in the Treasury before January 1, 1980, and attributable to liabilities incurred during 1978, over

(B) the sum of—

(i) the estimated reduction in the taxes imposed by chapter 1 of the Internal Revenue Code of 1954 resulting from the imposition for the calendar year 1978 of taxes by section 4986 of such Code, plus

(ii) the credits or payments allowed or made under section 4987(c) for 1978.

(2) METHOD OF TRANSFER.—The amounts appropriated by paragraph (1) shall be transferred at least quarterly from the general fund of the Treasury to the Trust Fund on the basis of estimates made by the Secretary of the amounts referred to in paragraph (1)(A) received in the Treasury, properly reduced for that portion of the sum referred to in paragraph (1)(B) which is attributable to such amounts. Proper adjustments shall be made in the amounts subsequently transferred to the extent prior estimates were in excess of or less than the amounts required to be transferred.

(c) USE OF AMOUNTS IN THE TRUST FUND.—Amounts in the Trust Fund may be used only for—

(1) making the payments provided by sections 2035, 2036, 2037, and 2040 of the Energy Tax Act of

1977 and section 6429 of the Internal Revenue Code of 1954,

(2) the payment or reimbursement of the administrative costs in connection with the making of the payments referred to in paragraph (1), and

(3) the aggregate amount of the credits allowable under section 44E of the Internal Revenue Code of 1954 solely by reason of subsection (d)(2) of such section 44E,

and such amounts are authorized to be appropriated for such purposes.

(d) TERMINATION.—The Secretary shall transfer from the Trust Fund into the general fund of the Treasury any amount in the Trust Fund at the close of December 31, 1979, which is not obligated for expenditure.

SEC. 2034. PER TAXPAYER CREDIT OF CRUDE OIL EQUALIZATION TAX RECEIPTS.

(a) IN GENERAL.—Subpart A of part IV of subchapter A of chapter 1 (relating to credits allowable) is amended by inserting after section 44D the following new section:

"SEC. 44E. CRUDE OIL EQUALIZATION TAX RECEIPTS CREDIT.

"(a) GENERAL RULE.—In the case of an individual, there shall be allowed as a credit against the tax imposed by this chapter for the taxpayer's first taxable year beginning in 1978 an amount equal to the crude oil payment for 1978.

"(b) 2 PAYMENTS IN THE CASE OF A JOINT RETURN OR A HEAD OF HOUSEHOLD.—In the case of—

"(1) a joint return made under section 6013, or

"(2) a head of household (within the meaning of section 2(b)),

the amount of the credit allowable by subsection (a) shall be equal to 2 times the crude oil payment for 1978.

"(c) AMOUNT OF PAYMENT.—The Secretary, in consultation with the Secretary of Energy, shall publish in the Federal Register before October 1, 1978, the amount of the crude oil payment for 1978. The Secretary shall determine such amount by dividing—

"(1) the estimated revenues to be derived from the taxes imposed by section 4986 for calendar year 1978, reduced by the sum of—

"(A) the estimated reduction in the taxes imposed by this chapter resulting from the imposition for the calendar year 1978 of taxes by section 4986,

"(B) the estimated aggregate amount with respect to the calendar year 1978 which will be credited or paid under section 6429 (relating to payments for heating oil for residences, hospitals, schools, and churches) or 4987(c)(1) (relating to credits or payments to refiners who use crude oil), and

"(C) the estimated administrative costs to be borne by the United States in connection with sections 2035, 2036, 2037, and 2040 of the Energy Tax Act of 1977, and in connection with the operation of section 6429 of this title with respect to the calendar year 1978, by

"(2) the estimated number of crude oil payments for 1978.

"(d) LIMITATION BASED ON AMOUNT OF TAX.—

"(1) IN GENERAL.—The credit allowed by subsection (a) shall not exceed the tax imposed by this chapter for the taxable year, reduced by the sum of the credits allowable under a section of this part having a lower number or letter designation than this section, other than the credits allowable by sections 31, 39, and 43.

"(2) REFUND MADE IF TAXPAYER IS ENTITLED TO EARNED INCOME CREDIT.—Paragraph (1) shall not apply to any individual who, for his first taxable year beginning in 1978, is entitled to a credit under section 43 (relating to credit for earned income). For purposes of section 6401(b), the amount of the credit allowable by reason of the preceding sentence shall be treated as a credit allowed by section 43.

"(e) CERTAIN PERSONS NOT ELIGIBLE.—This section shall not apply to any estate or trust, nor shall it apply to any nonresident alien individual."

(b) TECHNICAL AMENDMENT.—Subsection (b) of section 6096 is amended by striking out "and 44D" and inserting in lieu thereof "44D, and 44E".

(c) CLERICAL AMENDMENT.—The table of sections for subpart A of part IV of subchapter A of chapter 1 is amended by inserting after the item relating to section 44C the following new item:

"Sec. 44E. Crude oil equalization tax receipts credit."

(d) WITHHOLDING.—The tables prescribed under section 3402(a) of the Internal Revenue Code of 1954 which apply to wages paid during 1978 shall reflect the reductions in the withholding amounts which the Secretary of the Treasury estimates (as of October 1, 1977) will be appropriate in the light of the credit provided by section 44E of such Code.

SEC. 2035. SPECIAL PAYMENT TO RECIPIENTS OF BENEFITS UNDER SOCIAL SECURITY, RAILROAD RETIREMENT, AND SUPPLEMENTAL SECURITY INCOME PROGRAMS.

(a) PAYMENT.—Except as otherwise provided in this section, the Secretary of the Treasury shall, before October

1, 1979, make a payment equal to the crude oil payment for 1978 (as determined under section 44E(c) of the Internal Revenue Code of 1954) to each individual who, for the month of May 1979 (June 1979 in the case of a supplemental security income benefit), was entitled to—

(1) a monthly benefit payable under title II of the Social Security Act,

(2) a monthly annuity or pension under the Railroad Retirement Act of 1935, the Railroad Retirement Act of 1937, or the Railroad Retirement Act of 1974, or

(3) a benefit under the supplemental security income benefits program established by title XVI of the Social Security Act (as an eligible individual or as an eligible spouse).

The determination of whether an individual was entitled for May 1979 to a benefit described in paragraph (1) shall be made without regard to sections 202(j)(1) and 223(b) of the Social Security Act; and the determination of whether an individual was entitled for such month to an annuity or pension described in paragraph (2) shall be made without the application of section 5(a)(ii) of the Railroad Retirement Act of 1974.

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(b) SPECIAL RULES.—In the application of subsection (a)—

(1) payment under subsection (a) shall be made only to an individual who is paid the benefit, annuity, or pension for May or June (as the case may be) of 1979 in a check issued no later than June 30, 1979;

(2) no payment under subsection (a) shall be made to any individual who is not a resident of the United States; and

(3) no individual shall be entitled to receive more than one payment under subsection (a).

For purposes of this subsection, the term "resident of the United States" means an individual whose address of record for purposes of paying the benefit, annuity, or pension for May or June (as the case may be) of 1979 is located within the United States. For purposes of the preceding sentence, the term "United States" means the 50 States and the District of Columbia.

(c) LIMITATION ON PAYMENT WHERE INDIVIDUAL RECEIVES INCOME TAX CREDIT.—Notwithstanding any other provision of this section, if any individual otherwise entitled to a payment under subsection (a) shows on his return of tax under chapter 1 of the Internal Revenue Code of 1954 a credit under section 44E of such Code, the amount of the payment to which such individual would otherwise be entitled under subsection (a) shall be reduced (but not below zero) by the amount of the credit so shown under such section 44E (determined as of June 1, 1979).

(d) CERTAIN CHILDREN EXCLUDED.—No payment shall be made under this section to an individual described in section 202(d) of the Social Security Act unless such individual is entitled to a benefit under section 202(d)(1)(B)(ii) of the Social Security Act (relating to disabled adult children).

(e) TERMINATION.—No payment shall be made under this section to any individual unless the name of such individual has been submitted to the Treasury under section 2038(a)(1) before August 1, 1979.

SEC. 2036. SPECIAL PAYMENT TO RECIPIENTS OF AID TO FAMILIES WITH DEPENDENT CHILDREN UNDER APPROVED STATE PLANS.

(a) PAYMENT.—Every State which has in effect a plan for aid and services to needy families with children approved under section 402(a) of such Act shall, before October 1, 1979, make a payment equal to the crude oil payment for 1978 (as determined under section 44E(c) of the Internal Revenue Code of 1954) to each individual who, for the month of June 1979—

(1) received aid to families with dependent children under the plan as a relative with whom a dependent child was living, or

(2) was the spouse of such relative living with such relative, or was an adult individual living in the same home whose needs were taken into account in making the determination under section 402 (a) (7) of such Act.

(b) Two Payments Where Relative Is Head of Household.—If for the month of June 1979 the relative referred to in subsection (a) (1) was either not married or not living with such relative's spouse, the amount of the payment under subsection (a) shall be 2 times the crude oil payment for 1978.

(c) Special Rules.—In the application of subsection (a)—

(1) payment under subsection (a) shall be made only to individuals with respect to whom aid to families with dependent children for June 1979 is paid in a check issued no later than June 30, 1979; and

(2) in the case of an individual who is entitled for May 1979 to a benefit, annuity, or pension under a program referred to in paragraph (1) or (2) of section 2035, the amount of the payment to which such individual would otherwise be entitled under subsection (a) shall be reduced by the amount to which such individual

is entitled under section 2035 (determined without regard to subsection (c) thereof).

Compliance by any State with the requirement of subsection (a) shall be a condition of its eligibility for Federal financial participation under section 403 of the Social Security Act for the first calendar quarter of 1980, and the State's plan approved under section 402 (a) of such Act shall be deemed to so provide.

(d) FULL FEDERAL REIMBURSEMENT OF STATE COSTS.—Notwithstanding any other provision of law (or of any State plan approved under section 402 (a) of the Social Security Act), the Secretary of the Treasury shall pay to each State, in advance on the basis of satisfactory estimates or by way of reimbursement, the full amount of all payments made by such State under subsection (a), plus an additional sum, as compensation for the administrative costs incurred in connection with such payments, equal to the product of $2 multiplied by the number of relatives referred to in subsection (a) (1) who for June 1979 received aid to families with dependent children under the State plan.

(e) STATE DEFINED.—For purposes of this section, the term "State" includes the District of Columbia.

SEC. 2037. OTHER SPECIAL PAYMENTS.

(a) PAYMENT.—The Secretary of the Treasury shall, at the earliest practicable date after September 30, 1979, make a payment under this section to each individual who, on or before December 31, 1979, files a request with the Secretary for payment under this section. Such request shall be in such form, and filed in such manner, as the Secretary may by regulations prescribe and shall include such individual's social security account number.

(b) ELIGIBILITY FOR PAYMENT.—An individual shall be eligible for payment under this section only if—

(1) on December 31, 1978, such individual was a resident of the United States (as defined in the last sentence of section 2035 (b)) who had attained age 18, and

(2) such individual has not received by reason of section 44E of the Internal Revenue Code of 1954 and sections 2035 and 2036 of this Act the full amount of the payment to which he is entitled under this section.

(c) AMOUNT OF PAYMENT.—The amount of the payment to which an individual is entitled under this section shall be—

(1) the amount of the crude oil payment for 1978 (determined under section 44E (c) of the Internal Revenue Code of 1954), reduced by

(2) the sum of—

(A) the amount of the credit under such section 44E shown on such individual's return, and

(B) the amounts (if any) of the payments to such individual under sections 2035 and 2036 of this Act.

(d) TWO PAYMENTS FOR HEAD OF HOUSEHOLDS.—In the case of an individual who was a head of household (within the meaning of section 2 (b) of the Internal Revenue Code of 1954) as of December 31, 1978, the amount taken into account under subsection (c) (1) shall be 2 times the amount set forth therein.

SEC. 2038. PROVISIONS APPLICABLE TO SPECIAL PAYMENTS GENERALLY.

(a) RECIPIENT IDENTIFICATION.—

(1) IN GENERAL.—Notwithstanding any provision of Federal law heretofore enacted—

(A) the Secretary of Health, Education, and Welfare and the Railroad Retirement Board (i) shall provide the Secretary of the Treasury with such information and data, in such form and after such processing, as the Secretary of the Treasury may determine to be necessary to enable him to make the payments authorized under section 2035 or 2037 (and to determine the amount of any such payment), and (ii) shall provide the State agencies referred to in subparagraph (B) of this paragraph with such information and data, in such form and after such processing, as the Secretary may determine to be necessary to enable them to exercise their responsibilities under section 2036; and

(B) the appropriate agency of each State administering or supervising the administration of its State plan approved under section 402 of the Social Security Act and the Secretary of Health, Education, and Welfare shall furnish the Secretary of the Treasury with such information and data, in such form and after such processing, as the Secretary of the Treasury may determine to be necessary to enable him to exercise his responsibilities under this subpart.

(2) RESTRICTION ON USE AND DISCLOSURE OF INFORMATION.—Information and data furnished by any officer or agency to the Secretary of the Treasury or to another officer or agency under paragraph (1) shall be used by the Secretary or such other officer or agency only for purposes directly connected with carrying out the relevant provisions of this subpart, and the Secretary and such other officer or agency shall establish such safeguards as may be necessary to restrict the use or disclosure of such information and data to those purposes.

(b) PAYMENTS TO BE MADE AS SOON AS PRACTICABLE, ETC.—

(1) IN GENERAL.—Payments under this subpart shall be made as soon as practicable. If the Secretary of the Treasury determines that, because of the lack of information on compatible computer tapes or for similar reasons, the application of subsection (b) (3) or (c) of section 2035, of subsection (c) (2) of section 2036, or of subsection (c) (2) (B) of section 2037 will unduly postpone the making of payments under this subpart to any category of individuals or would unduly increase the costs of administering this subpart, the Secretary shall waive the application of that provision to such category of individuals. In the case of any waiver under the preceding sentence, the Secretary of the Treasury shall promptly notify the Congress of the waiver, the category of individuals affected by the waiver, the circumstances surrounding the waiver, and the reasons why such waiver is necessary to carry out the purposes of this subpart.

(2) RELIEF FROM LIABILITY.—Under regulations prescribed by the Secretary, in the absence of fraud or gross negligence, to the extent any erroneous payment is attributable to subsection (b) (3) or (c) of section 2035, to subsection (c) (2) of section 2036, or to subsection (c) (2) (B) of section 2037—

(A) the recipient of such payment shall not be liable to repay such payment, and

(B) all fiscal, disbursing, and other officers shall be relieved of liability with respect to the making of such payment.

(c) SPECIAL RULE FOR JOINT RETURNS.—For purposes of sections 2035 and 2037, in the case of a joint return of the tax imposed by chapter 1 of the Internal Revenue Code of 1954, one-half of the credit under section 44E of such Code shown on such return shall be allocated to each spouse.

(d) COORDINATION WITH OTHER FEDERAL PROGRAMS.—Any payment made to any individual by the Secretary of the Treasury under section 2035 or 2037 or by a State under section 2036 (a) (and any credit to an individual under section 44E of the Internal Revenue Code of 1954 which exceeds such individual's tax liability) shall not be regarded as income (or, in the calendar year 1979 or 1980, as a resource) of such individual (or of such individual's family) for purposes of any Federal, State, or local program which undertakes to furnish aid or assistance to individuals or families, where eligibility to receive such aid or assistance (or the amount of such aid or assistance) under such program is based on the need therefor of the individual or family involved. The requirement imposed by the preceding sentence shall be treated as a condition for Federal financial participation in any such State or local program of aid or assistance for the first calendar quarter of 1980.

(e) PAYMENTS NOT TO BE CONSIDERED INCOME.—Payments made under sections 2035, 2036, and 2037 shall not be considered as gross income for purposes of the Internal Revenue Code of 1954.

SEC. 2039. REFUNDS OF CRUDE OIL EQUALIZATION TAXES FOR RESIDENTIAL, ETC., USE.

(a) IN GENERAL.—Subchapter B of chapter 65 (relating to rules of special application for abatements, credits, and refunds) is amended by adding at the end thereof the following new section:

"SEC. 6429. HEATING OIL FOR RESIDENCES, HOSPITALS, SCHOOLS, AND CHURCHES.

"(a) PAYMENTS.—

"(1) IN GENERAL.—If any heating oil has been sold and delivered into the tank of an exempt structure for use in such structure, the Secretary shall pay (without interest) to the ultimate vendor of such oil an amount per gallon determined under subsection (c).

"(2) PAYMENTS MUST BE PASSED ON TO USER.—No payment may be made under paragraph (1) with respect to any heating oil unless the ultimate vendor furnishes such evidence as may be prescribed by the Secretary by regulations that the price of heating oil will not be increased to reflect any portion of the tax imposed by section 4986 for which payment is claimed.

"(b) EXEMPT STRUCTURE DEFINED.—For purposes of subsection (a), the term 'exempt structure' means any building or other structure 80 percent or more of the internal usable space of which is used as—

"(1) a residence, or

"(2) a hospital, school, or church.

"(c) AMOUNT PER GALLON.—On or before December 1 of 1977 and of each subsequent calendar year the Secretary, after consultation with the Secretary of Energy, shall determine the amount per gallon which will be applicable under subsection (a) for sales by ultimate vendors occurring during the succeeding calendar year. The Secretary shall determine such amount per gallon by dividing—

"(1) the estimated revenues to be derived from the taxes imposed by section 4986 for such succeeding calendar year, reduced by the estimated reduction in the taxes imposed by chapter 1 resulting from the imposition for such succeeding calendar year of taxes by section 4986, by

"(2) the estimated number of gallons of petroleum and petroleum products to be used in the United States during such succeeding calendar year.

For purposes of the preceding sentence, if the tax imposed by section 4986 (a) applies to only a portion of any calendar year, such portion shall be substituted for the calendar year.

"(d) HEATING OIL DEFINED.—For purposes of this section, the term 'heating oil' means—

"(1) No. 2 distillate oil, and

"(2) residual fuel oil.

"(e) DEFINITIONS AND SPECIAL RULES RELATING TO RESIDENCES, HOSPITALS, SCHOOLS, AND CHURCHES.—For purposes of this section—

"(1) RESIDENCE.—The term 'residence' includes an apartment or other multifamily dwelling, but does not include lodging facilities where the predominant portion of the accommodations is used by transients.

"(2) MAXIMUM PAYMENT PER RESIDENTIAL UNIT.—The maximum amount allowed under this section with respect to any dwelling unit for any calendar year shall not exceed the applicable amount set forth in the schedule published by the Secretary as the amount of heating oil to be used in a representative dwelling unit for the calendar year concerned and for the region in which the dwelling unit is located.

"(3) SCHOOL.—The term 'school' means a public or private educational organization—

"(A) which normally maintains a regular faculty and curriculum and normally has a regularly enrolled body of pupils or students in attendance at the place where its educational activities are regularly carried on,

"(B) the primary function of which is to advance the educational or career objectives of individuals (rather than their avocational or recreational objectives), and

"(C) not more than 20 percent of the student course hours of which are normally hours devoted to courses enrollment in which would be disapproved by the Administrator of Veterans' Affairs under section 1723 of title 38 of the United States Code.

"(4) UNRELATED BUSINESS, INVESTMENT, ETC., USE NOT TAKEN INTO ACCOUNT.—In the case of a hospital, school, or church, there shall be taken into account only use which is an integral part of its function as a hospital, school, or church, as the case may be.

"(f) MONTHLY CLAIMS; ADVANCE PAYMENTS.—

"(1) MONTHLY CLAIMS.—The claim of any person for payment under this section with respect to such person's sales during such month shall be filed on or before such date as may be prescribed by the Secretary by regulations.

"(2) ADVANCE PAYMENTS.—The regulations prescribed under this subsection shall provide for—

"(A) at the election of the ultimate vendor, advance payments with respect to the estimated sales which will qualify for payment under this section for any month, and

"(B) a reconciliation of—

"(i) the advance payments made pursuant to subparagraph (A) for the calendar months during any period, with,

"(ii) the payments to which the ultimate vendor was entitled for such months.

"(g) APPLICABLE LAWS.—

"(1) IN GENERAL.—All provisions of law, including penalties, applicable in respect of the tax imposed by section 4986(a) shall, insofar as applicable and not inconsistent with this section, apply in respect of the payment provided for in this section to the same extent as if such payments constituted refunds of overpayments of the tax so imposed.

"(2) EXAMINATION OF BOOKS AND WITNESSES.—For the purpose of ascertaining the correctness of any claim made under this section, or the correctness of any payment made in respect of any such claim, the Secretary shall have the authority granted by paragraphs (1), (2), and (3) of section 7602 (relating to examination of books and witnesses) as if the claimant were the person liable for the tax.

"(h) REGULATIONS.—The Secretary may in the regulations under this section prescribe the conditions, not inconsistent with the provisions of this section, under which payments may be made under this section.

"(i) CROSS REFERENCES.—

"(1) For civil penalty for excessive claims under this section, see section 6675.

"(2) For fraud penalties, etc., see chapter 75 (section 7201 and following, relating to crimes, other offenses, and forfeitures)."

(b) CLERICAL AMENDMENT.—The table of sections for such subchapter B is amended by adding at the end thereof the following:

"Sec. 6429. Heating oil for residences, hospitals, schools, and churches."

(c) CONFORMING AMENDMENTS.—

(1) Subsection (a) of section 6675 (relating to excessive claims with respect to the use of certain fuels or lubricating oil) is amended by striking out "or" before "6427" and by inserting ", or 6429 (relating to heating oil for residences, hospitals, schools, and churches)" before "for an excessive amount".

(2) Subsection (b) of section 6675 is amended by striking out "or 6427" and inserting in lieu thereof "6427, or 6429".

(3) Sections 7210, 7603, and 7604(b) are each amended by striking out "6427(f)(2)" and inserting in lieu thereof "6427(f)(2), 6429(g)(2)".

(4) Subsection (a) of section 7605 is amended—

(A) by striking out "6427(f)(2)" the first place it appears and inserting in lieu thereof "6427(f)(2), 6429(g)(2)", and

(B) by striking out "or 6427(f)(2)" and inserting in lieu thereof "6427(f)(2), or 6429(g)(2)".

(5) Paragraph (1) of section 7609(c) is amended by striking out "or 6427(e)(2)" and inserting in lieu thereof "6427(f)(2), or 6429(g)(2)".

(6) Subsection (c) of section 7610 is amended by striking out "6427(e)(2)" and inserting in lieu thereof "6427(f)(2), 6429(g)(2)".

(d) Effective Date.—The amendments made by this section shall apply to heating oil sold after December 31, 1977, and before October 1, 1981.

SEC. 2040. PAYMENTS TO PUERTO RICO AND THE POSSESSIONS OF THE UNITED STATES.

(a) Submission of Plan.—The Governor of Puerto Rico and the Governor of each possession of the United States may submit to the Secretary of the Treasury a plan for the distribution of crude oil payments for 1978 among the residents of Puerto Rico or such possession, as the case may be.

(b) APPROVAL OF PLANS.—The Secretary of the Treasury shall (not later than 90 days after the date on which any plan is submitted under subsection (a)) approve such plan if he determines—

(1) that such plan will result in the distribution of approximately the same amounts to approximately the same individuals who are residents of such Commonwealth or possession as would be the case if the provisions of section 44E of the Internal Revenue Code of 1954 and the provisions of sections 2035, 2036, and 2037 of this Act applied with respect to such Commonwealth or possession, and

(2) that the costs of administering such plan will not be excessive.

(c) PAYMENTS.—In the case of any plan approved under subsection (b), the Secretary of the Treasury shall make a payment to the Governor of the Commonwealth or possession in an amount equal to the sum of—

(1) the product of—

(A) the amount of the crude oil payment for 1978 (determined under section 44E of the Internal Revenue Code of 1954), and

(B) the number of crude oil payments for 1978 which the Secretary of the Treasury estimates will be made under the plan, and

(2) the amount which the Secretary of the Treasury estimates will be necessary to administer the plan.

PART IV—EXCISE TAX ON BUSINESS USE OF OIL AND NATURAL GAS

SEC. 2041. EXCISE TAX ON BUSINESS USE OF OIL AND GAS.

(a) IN GENERAL.—Chapter 45 (as added by section 2031 (a)) is amended by adding at the end thereof the following new subchapter:

"Subchapter B—Tax on Business Use of Oil and Gas; Rebates

"PART I—TAX ON BUSINESS USE OF OIL AND GAS

"SEC. 4991. IMPOSITION OF TAX.

"(a) IN GENERAL.—There is hereby imposed a tax on each taxable use of oil or natural gas.

"(b) AMOUNT OF TAX ON OIL.—The amount of the tax imposed by subsection (a) with respect to oil shall be determined in accordance with the following table (adjusted in the case of calendar year 1981 and thereafter for the inflation adjustment provided in subsection (d)):

"If the taxable use occurs during calendar year—	The tax per barrel is— Tier 1	Tier 2	Tier 3
1979	$.30	$.30	None
1980	.60	.60	None
1981	1.00	1.00	None
1982	1.00	1.45	None
1983	1.00	2.00	$1.50
1984	1.00	2.50	1.50
1985 or thereafter	1.00	3.00	1.50

"(c) AMOUNT OF TAX ON NATURAL GAS.—

"(1) TIER 1 AND TIER 2.—The amount of the tax imposed by subsection (a) with respect to each million Btu of taxable use of natural gas which is classified in Tier 1 or Tier 2 is the excess (if any) of—

"(A) the natural gas target price per million Btu for the calendar year (determined under section 4994(a)) which is applicable with respect to such gas, over

"(B) the user acquisition cost per million Btu for such gas (determined under section 4994(d)).

"(2) TIER 3.—The amount of the tax imposed by subsection (a) with respect to a taxable use of natural gas which is classified in Tier 3 shall be determined in accordance with the following table (adjusted in the case of the calendar year 1981 and thereafter for the inflation adjustment provided in subsection (d)):

"If the Tier 3 taxable use occurs during calendar year—	The tax per million Btu of taxable use is—
1979	None
1980	None
1981	None
1982	None
1983	$.55
1984	.65
1985 or thereafter	.75

For cap on a Tier 3 taxable use of natural gas, see section 4994 (f).

"(d) INFLATION ADJUSTMENT.—The inflation adjustment for any calendar year is the percentage by which—

"(1) the implicit price deflator for the gross national product for the preceding calendar year (as shown in the first revision thereof), exceeds or is less than

"(2) the similar deflator for 1979 (as shown in the final revision thereof).

"(e) ROUNDING.—If, but for this subsection—

"(1) the amount of any per barrel tax under subsection (b), or

"(2) the amount of any tax per million Btu under subsection (c),

would include a fraction of a cent, such fraction shall be rounded to the nearest whole cent (or, in the case of ½ cent, rounded upwards to the nearest whole cent).

"(f) LIABILITY FOR TAX.—The tax imposed by this section shall be paid by the user.

"(g) TAX DUE ON JULY 1 OF FOLLOWING YEAR.—The tax imposed by this section for any calendar year shall be paid on or before July 1 of the succeeding calendar year.

"(h) AUTHORITY OF PRESIDENT TO SUSPEND IMPOSITION OF TAX.—

"(1) GRANT OF AUTHORITY.—If the President determines that the imposition of the tax imposed by subsection (a) would have an adverse economic effect, he may submit to the Congress a suspension plan providing for the suspension of part or all of such tax for the period (not exceeding 1 year) specified in the plan.

"(2) PLAN MUST STATE CIRCUMSTANCES.—Any plan submitted under paragraph (1) shall set forth the circumstances leading to the submission of the plan and the considerations which the President took into account in formulating the scope and duration of the plan.

"(3) TAKING EFFECT OF PLAN.—A suspension plan described in paragraph (1) shall take effect only if—

"(A) such plan is submitted to the Congress in accordance with section 2081(a) of the Energy Tax Act of 1977, and

"(B) before the close of the 15th day (as defined in section 2081(c)(5) of such Act) after the day on which such plan is delivered to the Congress, neither the House of Representatives nor the Senate disapproves such plan in accordance with the procedures set forth in section 2081(b) of such Act.

"**SEC. 4992. TAXABLE USE DEFINED.**

"(a) IN GENERAL.—For purposes of this part, the term 'taxable use' means any use (in the United States) as a fuel in a trade or business. Such term does not include—

"(1) any exempt use, and

"(2) so much of what would (but for this paragraph) be taxable use during the calendar year as does not exceed the exempt amount for the calendar year (determined under subsection (c)).

"(b) EXEMPT USE.—

"(1) IN GENERAL.—For purposes of subsection (a), the term 'exempt use' means—

"(A) use in an apartment, hotel, motel, or other residential facility,

"(B) use in a vehicle, aircraft, or vessel, or in transportation by pipeline,

"(C) use on a farm for farming purposes (within the meaning of section 6420(c)), "(D) use in—

"(i) a shopping center,

"(ii) an office building,

"(iii) a wholesale or retail establishment, or

"(iv) any other facility which is not an integral part of manufacturing, processing, or mining,

"(E) use in the exploration for, or the development, extraction, transmission, or storage of, crude oil, natural gas, or natural gas liquids, and

"(F) any exempt process use (within the meaning of paragraph (2)).

"(2) EXEMPT PROCESS USE DEFINED.—For purposes of this subsection, the term 'exempt process use' means the use of oil or natural gas in any manufacturing process where there is no substitute fuel—

"(A) which may be used without materially and adversely affecting the manufacturing process or the quality of the manufactured goods, and

"(B) the use of which is economically and environmentally feasible.

Such term does not include any use in a boiler or in a turbine or other internal combustion engine. For purposes of this paragraph, the term 'substitute fuel' means any fuel other than oil and natural gas.

"(3) USE PRECLUDED BY FEDERAL OR STATE AIR POLLUTION REGULATIONS.—

"(A) IN GENERAL.—For purposes of subsection (a), the term 'exempt use' includes any use of oil or natural gas in a facility if—

"(i) the use of coal in such facility is precluded by Federal or State air pollution regulations, and

"(ii) such facility was in existence on April 20, 1977, on such date construction of such facility had begun, or on such date there was a binding contract for the construction of such facility.

This subparagraph shall not apply to any use of oil or natural gas in a facility which is substantially different from the use contemplated for such facility on April 20, 1977.

"(B) STATE REGULATIONS MUST HAVE BEEN IN EFFECT ON APRIL 20, 1977, ETC.—For purposes of subparagraph (A), a State regulation shall be taken into account with respect to any use only if—

"(i) such use would also have been precluded by a regulation of such State which was in effect on April 20, 1977, or

"(ii) the Secretary, after consultation with the appropriate Federal and State agencies, determines that the adoption of the State regulation meets a requirement of Federal law.

"(C) REGULATIONS PURSUANT TO STATE IMPLEMENTATION PLAN.—For purposes of this paragraph, a regulation of an agency having jurisdiction over the facility under an approved State Implementation Plan shall be treated as a State regulation. For purposes of the preceding sentence, the term 'approved State Implementation Plan' means a plan of a State for the control of air pollution which has been approved by the appropriate Federal agency as implementing Federal laws relating to air pollution.

"(c) EXEMPT AMOUNT.—

"(1) IN GENERAL.—For purposes of this part, the exempt amount for the taxpayer for any calendar year is the Btu content of 50,000 barrels of oil.

"(2) ALLOCATION.—Under regulations prescribed by the Secretary, the taxpayer may allocate the exempt amount for any calendar year—

"(A) between oil and natural gas, and

"(B) among the various tiers of taxable use, in such manner as the taxpayer may elect.

"(3) ENTITIES UNDER COMMON CONTROL.—

"(A) TREATMENT AS 1 TAXPAYER.—For purposes of this subsection—

"(i) persons who are members of the same controlled group of corporations, and

"(ii) trades or businesses (whether or not incorporated) which are under common control, shall be treated as 1 taxpayer.

"(B) ALLOCATION OF EXEMPT AMOUNT.—The exempt amount for the calendar year shall be divided among the entities treated as 1 taxpayer under subparagraph (A)—

"(i) in proportion to their respective taxable use (determined without regard to subsection (a)(2)) during the calendar year, or

"(ii) if all such entities agree, in such proportions as may be agreed upon in such agreement.

"(C) DEFINITIONS.—For purposes of this paragraph—

"(i) CONTROLLED GROUP OF CORPORATIONS.—The term 'controlled group of corporations' has the meaning given to such term by section 1563(a), except that 'more than 50 percent' shall be substituted for 'at least 80 percent' each place it appears in section 1563(a).

"(ii) COMMON CONTROL.—The determination of whether trades or businesses are under common control shall be made under regulations prescribed by the Secretary which shall be based on principles similar to the principles which apply in the case of clause (i).

"(4) PER PLANT ADJUSTMENT IN CASES OF COMPETITIVE DISADVANTAGE.—If—

"(A) the taxpayer engages in a trade or business at any plant,

"(B) facilities located in the same region as the plant referred to in subparagraph (A) which are competitive with such plant do not incur any liability for the tax imposed by section 4991 by reason of the exempt amount, and

"(C) the liability for the tax imposed by section 4991 which the taxpayer would, but for this paragraph, incur with respect to uses in such plant would result in a substantial competitive disadvantage to the taxpayer, the Secretary shall provide an additional exempt amount for the calendar year which may be usable only in such plant but only to the extent that such additional exempt amount is necessary to alleviate the competitive disadvantage. The Secretary shall, as soon as practicable after any exempt amount is provided under the preceding sentence, publish in the Federal Register the name of the plant and the additional exempt amount for the calendar year.

"SEC. 4993. TIERS; DOWNWARD RECLASSIFICATION.

"(a) TIERS.—For purposes of this part, a taxable use shall be classified in one of the following 3 tiers:

"(1) Tier 1, which includes any use which is not classified in Tier 2 or 3.

"(2) Tier 2, which includes any use in a boiler or in a turbine or other internal combustion engine (other than a use classified in Tier 3).

"(3) Tier 3, which includes any use by an entity—

"(A) in the production of electricity—

"(i) for sale to another entity which is not under common control (within the meaning of section 4992 (c) (3) (C) (ii)), or

"(ii) in a plant with a rated capacity of 100 megawatts or more of electricity, "(B) in the production of steam by a regulated public utility the principal activity of which is the production of electricity for sale, or

"(C) in the production of electricity or other useful energy in a qualifying cogeneration facility (within the meaning of section 546(b)(2) of the National Energy Act).

"(b) RECLASSIFICATION DOWNWARD.—

"(1) IN GENERAL.—The Secretary shall prescribe by regulations a procedure under which he may reclassify, for a temporary period or permanently, a use to a Tier which is subject to a lower tax or in an exempt use category.

"(2) STANDARDS FOR RECLASSIFICATION.—The Secretary shall reclassify a use under paragraph (1) only after consulting the appropriate Federal agency, and only if he determines that such action is not inconsistent with the goal of encouraging the conversion from, or significant conservation in, the use of oil and natural gas as a fuel.

"SEC. 4994. AMOUNT OF NATURAL GAS TAX.

"(a) NATURAL GAS TARGET PRICE.—For purposes of section 4991(c)(1)(A)—

"(1) IN GENERAL.—The natural gas target price per million Btu for the calendar year applicable to gas used in any region is—

"(A) the Btu equivalency price for the calendar year for such region (determined under subsection (c)), reduced by

"(B) the amount of the taxable use adjustment (if any) provided by subsection (b),

"(2) INFLATION ADJUSTMENT.—In the case of a calendar year beginning after 1980, the amount taken into account under paragraph (1)(B) shall be adjusted for the inflation adjustment provided in section 4991(d)).

"(b) TAXABLE USE ADJUSTMENT.—For purposes of subsection (a), the taxable use adjustment for 1 million Btu is the amount of the subtraction determined in accordance with the following table:

"If the taxable use occurs during calendar year—	The amount subtracted for Tier 1 is—	The amount subtracted for Tier 2 is—
1979	$1.35	$1.05
1980	.70	.40
1981	.65	.35
1982	.55	.25
1983	.50	.20
1984	.45	.15
1985 or thereafter	.30	zero

"(c) DETERMINATION OF EQUIVALENCY PRICE.—For purposes of subsection (a) (1) (A)—

"(1) IN GENERAL.—The Btu equivalency price for the calendar year for any region shall be based on the average regional price per barrel of all No. 2 grade distillate oil sold during the preceding calendar year for taxable use in such region. For purposes of the preceding sentence, the Btu content of a barrel of No. 2 grade distillate oil is 5,800,000 Btu.

"(2) SECTION 4991 TAX NOT TAKEN INTO ACCOUNT.—The determination of Btu equivalency price shall be made without taking into account any tax imposed by section 4991.

"(3) DETERMINATION OF BTU EQUIVALENCY PRICE.—The Btu equivalency price for the calendar year shall be determined by the Secretary of Energy and certified to the Secretary on or before March 31 of the calendar year.

"(d) USER ACQUISITION COST.—For purposes of section 4991 (c) (1) (B)—

"(1) IN GENERAL.—The user acquisition cost of any person per million Btu for any acquisition of natural gas is—

"(A) the aggregate amount paid by such person for such gas, divided by

"(B) the number of million Btu so acquired.

"(2) IMPUTED COST.—In the case of natural gas—

"(A) used—

"(i) by the producer thereof,

"(ii) by any person who is a member of the same controlled group of corporations as the producer thereof, or

"(iii) in any trade or business (whether or not incorporated) which is under common control with the producer, or

"(B) acquired in a transaction which is not an arm's length transaction.

the user acquisition cost shall not exceed the maximum lawful price (or special price) applicable with respect to a sale by the producer of such natural gas under law of the United States.

"(3) COST TO INCLUDE TRANSPORTATION COSTS.—For purposes of this subsection—

"(A) transportation costs include imputed transportation costs, and

"(B) transportation costs shall not exceed the reasonable transportation costs which would be incurred in an arm's length transaction.

"(4) NEW OR INCREASED STATE USER TAXES NOT TAKEN INTO ACCOUNT.—

"(A) IN GENERAL.—For purposes of this subsection—

"(i) any State natural gas user tax imposed on or after April 20, 1977, and

"(ii) any increase on or after such date in the rate of a State natural gas user tax,

shall not be taken into account.

"(B) DEFINITIONS.—For purposes of subparagraph (A)—

"(i) the term 'State' includes a political subdivision of a State, and

"(ii) any tax, fee, or other amount having the effect of a user tax shall be treated as a user tax.

"(e) REDUCTION IN TIER 1 AND TIER 2 TAX FOR INTERRUPTIBLE CONTRACTS.—

"(1) IN GENERAL.—If any portion of the natural gas is acquired pursuant to an interruptible contract, the amount of the tax determined under section 4991 (c) (1) with respect to such portion shall be reduced by an amount equal to 10 percent of the amount determined without regard to this paragraph.

"(2) INTERRUPTIBLE CONTRACT DEFINED.—For purposes of paragraph (1), the term 'interruptible contract' means a contract or schedule which anticipates and permits interruptions by the supplies on short notice in nonemergency situations.

"(f) CAP ON TAX ON UTILITY USE.—

"(1) IN GENERAL.—The tax on any taxable use of natural gas classified in Tier 3 shall not cause the cost of such use to exceed the Btu equivalency price for residual fuel oil.

"(2) BTU EQUIVALENCY PRICE.—For purposes of paragraph (1), the Btu equivalency price for residual fuel oil shall be determined—

"(A) on the basis of the average regional price per barrel of all residual fuel oil sold during the preceding calendar year for taxable use in the region in which the natural gas is used, as determined by March 31 of the calendar year by the Secretary of Energy, and

"(B) by including in the cost of the natural gas, and in the regional price for residual fuel oil, the taxes imposed by this chapter.

"(3) BTU CONTENT OF RESIDUAL FUEL OIL.—For purposes of this subsection, the Btu content of a barrel of residual fuel oil is 6,200,000 Btu.

"(g) DETERMINATION OF REGIONS.—For purposes of this section, the Secretary, after consultation with the Secretary of Energy, shall divide the United States into such regions as may be appropriate to carry out the purposes of the tax imposed by section 4991 on the taxable use of natural gas.

"SEC. 4995. DEFINITIONS AND SPECIAL RULES.

"(a) OIL.—

"(1) IN GENERAL.—For purposes of this part, except as provided in paragraph (2), the term 'oil' means—

"(A) crude oil,

"(B) refined petroleum products, and

"(C) natural gas liquids.

"(2) EXCEPTIONS.—The term 'oil' does not include—

"(A) natural gas,

"(B) gasoline (within the meaning of section 4082(b)), and

"(C) any substance of a kind which is not generally marketable for use as a fuel.

"(b) NATURAL GAS.—

"(1) IN GENERAL.—For purposes of this part, except as provided in paragraph (2), the term 'natural gas' means—

"(A) natural gas, petroleum, or a product of natural gas or petroleum, which

"(B) has an API gravity of 110 or more.

"(2) EXCEPTION.—The term 'natural gas' does not include any substance of a kind which is not generally marketable for use as a fuel.

"(c) BARREL.—For purposes of this part, the term 'barrel' means 42 gallons.

"(d) AMOUNT OF TAX ON FRACTIONAL UNITS.—In the case of a fraction of a barrel of oil or (in the case of natural gas) a fraction of 1 million Btu, the amount of the tax shall be the same fraction of the amount determined under subsection (b) or (c) of section 4991 (whichever applies).

"(e) BTU CONTENT.—For purposes of this part—

"(1) OIL.—Except as otherwise provided in this part, the Btu content of a barrel of oil is 6,000,000 Btu.

"(2) NATURAL GAS.—The Secretary shall by regulations establish Btu content for the various types and grades of natural gas.

"(f) UNITED STATES.—For purposes of this part, the term 'United States' means the 50 States and the District of Columbia."

(b) EFFECTIVE DATE.—The amendment made by subsection (a) shall apply to uses after December 31, 1978.

PART V—CREDIT AGAINST TAX ON BUSINESS USE OF OIL AND GAS

SEC. 2051. CREDIT AGAINST TAX ON BUSINESS USE OF OIL AND GAS.

Subchapter B of chapter 45 (as added by section 2041) is amended by adding at the end thereof the following new part:

"PART II—CREDITS AGAINST SECTION 4991 TAX

"SEC. 4996. ALLOWANCE OF CREDIT.

"(a) GENERAL RULE.—There shall be allowed as a credit against the tax imposed by section 4991 for the calendar year the amount determined under this part.

"(b) REGULATIONS.—The Secretary shall prescribe such regulations as may be necessary to carry out the purposes of this part.

"(c) TERMINATION OF CREDIT.—

"(1) IN GENERAL.—Except as provided in paragraph (2), no credit shall be allowed under this section for any calendar year beginning after December 31, 1990.

"(2) EXCEPTION WHERE CONSTRUCTION, ETC., BEGINS BEFORE 1091.—Paragraph (1) shall not apply to property—

"(A) the physical construction, reconstruction, or erection of which is begun before January 1, 1991, or

"(B) which is acquired by the taxpayer before such date.

"(d) CREDIT AVAILABLE ONLY WHERE ELECTION MADE.—No credit shall be allowed under this section for any calendar year unless an election under section 4999 (a) is in effect for such year.

"(e) APPLICATION OF CREDIT IN THE CASE OF CONTROLLED GROUP, ETC.—

"For application of the credit in the case of 2 or more related entities, see section 4999(b).

"SEC. 4997. AMOUNT OF CREDIT.

"(a) GENERAL RULE.—The amount of the credit allowed under section 4996 for the calendar year shall be an amount equal to the lesser of—

"(1) 100 percent of the qualified energy investment for such year, or

"(2) the section 4991 tax for such year.

"(b) QUALIFIED ENERGY INVESTMENT FOR YEAR.—For purposes of this part—

"(1) IN GENERAL.—The qualified energy investment for any calendar year is the sum of—

"(A) the aggregate bases of section 4996 property (as defined in section 4998(a)) placed in service by the taxpayer during such year (reduced in a manner similar to that provided by section 46(c)(4)),

"(B) the qualified progress expenditures with respect to section 4996 property, and

"(C) the energy investment carryover to such year.

"(2) DETERMINATION OF QUALIFIED PROGRESS EXPENDITURES.—For purposes of paragraph (1)(B), qualified progress expenditures shall be determined in a manner similar to that provided by section 46(d) (including the requirement of an election), except that—

"(A) the term 'person' shall be substituted for 'taxpayer' each place it appears in section 46(d), and

"(B) paragraph (7) of section 46(d) shall not apply.

"(3) ENERGY INVESTMENT CARRYOVER TO SUCCEEDING YEAR.—If the sum described in paragraph (1) for any calendar year exceeds the tax imposed by section

4991 for such year, such excess shall be an energy investment carryover to the succeeding calendar year.

"(c) SECTION 4991 TAX FOR YEAR.—For purposes of this part—

"(1) IN GENERAL.—Except as provided in paragraph (2), the section 4991 tax for any calendar year is the amount of the tax imposed by section 4991 for such year.

"(2) TAX LIABILITY FOR 1979 AND 1980 MAY BE CARRIED TO 1981.—

"(A) 1979 LIABILITY.—Any excess of—

"(i) the liability for the tax imposed by section 4991 for 1979, over

"(ii) the qualified energy investment for 1979,

shall be treated as tax imposed by section 4991 for 1980.

"(B) 1980 LIABILITY.—Any excess of—

"(i) the liability for the tax imposed by section 4991 for 1980 (including any excess determined under subparagraph (A)), over

"(ii) the qualified energy investment for 1980,

shall be treated as tax imposed by section 4991 for 1981.

"(C) OVERPAYMENTS OF TAX.—Any portion of the excess described in subparagraph (A) or (B), which is offset by a credit for the year under section 4996 shall be treated as an overpayment of the tax imposed by section 4991 for such credit year.

"(d) SPECIAL RULE WHERE PROPERTY IS FINANCED BY INDUSTRIAL DEVELOPMENT BONDS.—In the case of any property which is financed in whole or in part by the proceeds of an industrial development bond (within the meaning of section 103(b)(2)) the interest on which is exempt from tax under section 103, the amount of the credit allowed under section 4996 shall be determined by substituting '50 percent' for '100 percent' in subsection (a)(1) of this section.

"SEC. 4998. SECTION 4996 PROPERTY.

"(a) SECTION 4996 PROPERTY DEFINED.—For purposes of this part, the term 'section 4996 property' means alternative energy property which is tangible property (not including a building and its structural components) and—

"(1) which is used by the taxpayer in the taxpayer's trade or business (other than the trade or business of leasing),

"(2) with respect to which depreciation (or amortization in lieu of depreciation) is allowable, "(3) which has a useful life (determined as of the time such property is placed in service) of 3 years or more,

"(4) which is not used predominantly outside the United States (determined in a manner similar to that provided by subparagraphs (A) and (B) of section 48 (a) (2)), and

"(5) which is new property.

"(b) ALTERNATIVE ENERGY PROPERTY DEFINED.—For purposes of this part—

"(1) IN GENERAL.—The term 'alternative energy property' means—

"(A) a boiler the primary fuel for which will be an alternate substance,

"(B) a burner (including necessary on-site equipment to bring the alternate substance to the burner) for a combustor other than a boiler if the primary fuel for such burner will be an alternate substance,

"(C) equipment used in the production of energy by nuclear, hydroelectric, or geothermal power, but not including the fuel and not including turbines or equipment beyond the turbine stage,

"(D) equipment for converting an alternate substance into synthetic gas, "(E) pollution control equipment required (by Federal, State, or local regulations) to be installed on or in connection with equipment described in subparagraph (A), (B), or (D),

"(F) equipment used for the unloading, transfer, storage, reclaiming from storage, and preparation (including washing, crushing, drying, and weighing at the point of use) of an alternate substance for use—

"(i) in equipment described in subparagraph (A), (B), (C), (D), or (E), or

"(ii) in a facility which uses coal as a feedstock for the manufacture of chemicals or other products (except coke), and

"(G) the basis for plans and designs for equipment described in subparagraph (A), (B), (C), (D), (E), or (F).

"(2) ALTERNATE SUBSTANCE.—The term 'alternate substance' means any substance other than—

"(A) oil and natural gas, and

"(B) any product of oil and natural gas.

"(3) SPECIAL RULE FOR CERTAIN POLLUTION CONTROL EQUIPMENT.—The term 'pollution control equipment' does not include any equipment which—

"(A) is installed on or in connection with property which, as of April 20, 1977, was using coal, and

"(B) was required to be installed by Federal, State, or local regulations in effect on such date.

"(4) EQUIPMENT USING OIL AND ANOTHER SUBSTANCE.—

"(A) IN GENERAL.—A qualified oil-alternative substance boiler shall be treated as a boiler described in paragraph (1) (A).

"(B) QUALIFIED OIL-ALTERNATIVE SUBSTANCE BOILER DEFINED.—For purposes of subparagraph (A), the term 'qualified oil-alternative substance boiler' means an existing boiler for an existing electric generator facility—

"(i) before modification the fuel for which is oil or natural gas, and

"(ii) after modification the fuel for which will be oil mixed with an alternate substance, with such substance providing not less than 25 percent and not more than 50 percent of the total fuel.

For purposes of this subparagraph, the term 'existing' has the meaning given to such term by section 48 (l) (9).

"(C) PARTIAL CREDIT.—The amount of the credit allowed under section 4996 with respect to any qualified oil-alternative substance boiler shall be determined by substituting 'the oil-saving percentage' for '100 percent' in section 4997 (a) (1). For purposes of this subparagraph, the term 'qualified oil-alternative substance boiler' includes any equipment described in subparagraph (E) or (F) of paragraph (1) or plans or designs described in paragraph (1) (G) which are properly allocable to such boiler.

"(D) OIL-SAVING PERCENTAGE.—For purposes of subparagraph (C), the term 'oil-saving percentage' means whichever of the following percentages is the smaller:

"(i) the percentage derived from the fraction the numerator of which is the energy for the boiler which will be supplied by the alternative substance and the denominator of which is the energy which will be provided by all substances, or

"(ii) the percentage derived from the fraction the numerator of which is the decrease in oil and natural gas energy used as a fuel by the boiler as a result of the modification, and the denominator of which is the oil and natural gas energy which would have been used in the boiler as a fuel if there had been no modification.

For purposes of this subparagraph, energy shall be determined in terms of British thermal units on the basis of normal use over the useful life of the boiler.

"(c) New Property.—For purposes of this part, the term 'new property' means property—

"(1) the construction, reconstruction, or erection of which is completed by the taxpayer on or after April 20, 1977, or

"(2) acquired by the taxpayer on or after April 20, 1977, if the original use of such property commences with the taxpayer and commence on or after such date.

In applying this part in the case of property described in paragraph (1), there shall be taken into account only that portion of the basis which is properly attributable to construction, reconstruction, or erection on or after April 20, 1977.

"(d) Oil and Natural Gas.—For purposes of this part—

"(1) the term 'oil' has the meaning given to such term by section 4995 (a) (1), and

"(2) the term 'natural gas' has the meaning given to such term by section 4995 (b) (1).

"(e) UNITED STATES.—For purposes of this part, the term 'United States' means the 50 States and the District of Columbia.

"SEC. 4999. SPECIAL RULES.

"(a) RULES RELATING TO ELECTION.—

"(1) TIME AND MANNER OF MAKING.—An election under this subsection may be made only on or before the last day prescribed by law (including extensions thereof) for filing the return of the tax imposed by chapter 1 for the first taxable year ending after December 31, 1978, for which the taxpayer has qualified energy investment. An election under this subsection shall be made in such manner as the Secretary may by regulations prescribe.

"(2) SPECIAL RULES FOR UTILITIES.—

"(A) IN GENERAL.—In the case of a regulated public utility the principal activity of which is the production of electricity, paragraph (1) shall be applied by substituting 'December 31, 1982' for 'December 31, 1978'.

"(B) RECAPTURE OF SECTION 38 CREDIT.—In the case of any taxpayer which (by reason of subparagraph (A)) makes an election under this subsection for its first taxable year ending after

December 31, 1982, the tax under chapter 1 for such taxable year shall be increased by an amount equal to the decrease in the credits under section 38 for all prior years which would have resulted solely from not taking into account any qualified investment which would have not been taken into account if the election under this subsection had been made at the time required by paragraph (1). In any such case carrybacks and carryovers under section 46(b) shall be properly adjusted.

"(3) ELECTION REVOCABLE ONLY WITH CONSENT.—An election made under this subsection, once made, may be revoked by the taxpayer only with the consent of the Secretary.

"(4) SCOPE OF ELECTION.—

"(A) IN GENERAL.—Except as provided in subparagraph (B), an election made under this subsection shall apply to all section 4996 property of the taxpayer.

"(B) ELECTION TO TAKE REGULAR INVESTMENT CREDIT INSTEAD OF A CARRYOVER UNDER SECTION 4996.—If the sum of the amounts described in subparagraphs (A) and (B) of section 4997(b)(1) for any calendar year exceeds the tax imposed by section 4991 for such year—

"(i) then the taxpayer may elect to treat part or all of such excess as property with respect to which the election under section 4999 (a) is not effective,

"(ii) the property with respect to which an election under clause (i) is made which is section 38 property shall be eligible for the regular percentage (but not the energy percentage) for purposes of the credit allowable under section 38, and

"(iii) the property referred to in clause (ii) shall not be taken into account in determining the energy investment carryover under section 4997 (b) (3).

An election made under clause (i) with respect to any property, once made, may be revoked by the taxpayer only with the consent of the Secretary.

"(b) ENTITIES UNDER COMMON CONTROL.—

"(1) TREATMENT AS 1 TAXPAYER.—For purposes of applying this part—

"(A) persons who are members of the same controlled group of corporation, and

"(B) trades or businesses (whether or not incorporated) which are under common control,

shall be treated as 1 taxpayer.

"(2) DEFINITIONS.—For purposes of paragraph (1)—

"(A) the term 'controlled group of corporation' has the meaning given to such term by clause (i) of section 4992 (c) (3) (C), and

"(B) the determination of whether trades or businesses are under common control shall be made as provided in clause (ii) of section 4992 (c) (3) (C).

"(3) ENTITIES BECOMING RELATED AFTER ELECTION.—The Secretary shall prescribe regulations for the application of paragraph (1) where, after the making by any entity of an election under subsection (a), such entity becomes related (within the meaning of paragraph (1)) to a second entity with respect to which (but for paragraph (1)) an election would not be in effect.

"(c) CERTAIN DISPOSITIONS, ETC., OF SECTION 4996 PROPERTY.—

"(1) IN GENERAL.—If during any calendar year any property is disposed of, or otherwise ceases to be section 4996 property with respect to the taxpayer, within 7 years of the time such property was placed in service by the taxpayer, then the tax under section 4991 for the calendar year in which such disposition or cessation occurs shall be increased by an amount equal to the aggregate decrease in the credits allowed under this part for all prior calendar years which would have resulted solely from not taking such property into account.

"(2) PHASEDOWN OF RECAPTURE.—If the period described in paragraph (1) is—

"(A) 3 years or more but less than 5 years, the amount of the recapture shall be $\frac{2}{3}$ of the amount which (but for this paragraph) would be subject to recapture, or

"(B) 5 years or more but less than 7 years, the amount of the recapture shall be $\frac{1}{3}$ of the amount which (but for this paragraph) would be subject to recapture.

"(3) CERTAIN RULES MADE APPLICABLE.—For purposes of this subsection, under regulations prescribed by the Secretary, rules similar to paragraphs (3) (other than subparagraph (C) thereof) and (4) of subsection (a) of section 47 (relating to recapture of business investment credit) and to subsection (b) of section 47 shall apply.

"(d) UTILITY ALLOWED CREDIT FOR NEW BOILER ONLY TO EXTENT OIL OR GAS BOILER IS REPLACED OR PHASED DOWN.—

"(1) IN GENERAL.—In the case of a regulated public utility the principal activity of which is the production of electricity, a boiler (hereinafter in this subsection referred to as 'new boiler') shall be treated as section 4996 property—

"(A) only if the taxpayer establishes such facts as the Secretary may by regulations prescribe with respect to the replacement or phasing-down of a boiler (hereinafter in this subsection referred to as 'old boiler') which, as of April 20, 1977, used as its primary fuel oil or natural gas, and

"(B) only to the extent that there will be (not later than the calendar year following the credit year) a replacement or phasing-down of the old boiler.

"(2) PHASING DOWN.—For purposes of paragraph (1), the old boiler is phased down if (and only if)—

"(A) during 1976 it was used for more than 1,500 hours, and

"(B) during each calendar year after the credit year, the old boiler will be used for 1,500 hours or less.

"(3) TAX FOR USE BETWEEN 1,500 AND 2,000 HOURS.—If for any calendar year after the credit year the old boiler is used for more than 1,500 hours but not more than 2,000 hours, there is hereby imposed for such years a tax in an amount equal to the amount of the tax which would be imposed by section 4991 on the oil or natural gas used for such hours in excess of 1,500 if such use constituted a separate and additional taxable use. For purposes of the preceding sentence, taxable use shall be determined without regard to the second sentence of section 4992(a).

"(4) NO CREDIT ALLOWED AGAINST PARAGRAPH (3) AMOUNT.—No credit shall be allowed under section 4996 against any amount determined under paragraph (3).

"(5) RECAPTURE FOR USE IN EXCESS OF 2,000 HOURS.—If for any calendar year after the credit year the old boiler is used for more than 2,000 hours, for purposes of subsection (c) of this section the new boiler shall be treated as disposed of at the close of the year in which it is so used.

"(6) ADVANCE CERTIFICATION.—For purposes of this subsection, if the taxpayer—

"(A) certifies to the Secretary—

"(i) that the old boiler will be replaced or phased down beginning with the calendar year following the credit year, and "(ii) that the new boiler will be placed in service not later than 3 years after the first calendar year for which the certification is effective; and

"(B) agrees to an extension of the period for assessing any deficiency of the tax imposed by section 4991, to the extent such deficiency is attributable to the fact that such certification proves to be erroneous,

then, for purposes of paragraph (1) (but not for purposes of paragraphs (2), (3), (4), and (5)), the replacement or phasing down shall be treated as occurring on the date as of which the certification is effective.

"(7) CERTAIN BOILERS TREATED AS REPLACED.—If—

"(A) physical construction of a facility began before April 20, 1977,

"(B) as of April 20, 1977, such facility included (or it was contemplated that such facility would include) a boiler the primary fuel of which would be oil or natural gas, and

"(C) after April 20, 1977, the construction of such boiler is modified so it will use an alterna[illegible] substance, for purposes of paragraph (1), such boiler shall be treated as a new boiler replacing an existing boiler at the time it is placed in service.

"(8) BOILER DEFINED.—For purposes of this subsection, the term 'boiler' includes equipment described in subparagraph (E) or (F) of paragraph (1) of subsection (b) (or plans or designs described in subparagraph (G) of such paragraph (1)) properly allocable to the boiler.

"(9) CREDIT YEAR.—For purposes of this subsection, the term 'credit year' means the later of—

"(A) the calendar year in which the new boiler is placed in service, or

"(B) 1983.

"(e) COORDINATION WITH CHAPTER 1.—

"(1) ONLY NET TAX DEDUCTIBLE UNDER CHAPTER 1.—The amount allowable as a deduction under chapter 1 with respect to the tax imposed by section 4991 for any calendar year shall not exceed the amount of such tax reduced by the credit allowed under section 4996 for such year.

"(2) ADJUSTMENT IN THE CASE OF CARRYOVER OF TAX LIABILITY.—If a credit is allowed under section 4996 for 1980 or 1981 by reason of the carryover under section 4997(c)(2) of tax liability for 1979 or

1980, proper adjustments shall be made in the tax imposed by chapter 1 to reflect the amount allowed as a deduction under chapter 1 for such tax liability in a prior taxable year."

PART VI—CHANGES IN BUSINESS INVESTMENT CREDIT TO ENCOURAGE CONSERVATION OF, OR CONVERSION FROM, OIL AND GAS OR TO ENCOURAGE NEW ENERGY TECHNOLOGY

SEC. 2061. CHANGES IN BUSINESS INVESTMENT CREDIT.

(a) AMOUNT OF CREDIT; ALLOWANCE OF ENERGY PERCENTAGE.—

(1) IN GENERAL.—Paragraph (2) of section 46 (a) (relating to amount of credit for current taxable year) is amended to read as follows:

"(2) AMOUNT OF CREDIT.—

"(A) IN GENERAL.—The amount of the credit determined under this paragraph for the taxable year shall be an amount equal to the sum of the following percentages of the qualified investment (as determined under subsections (c) and (d)):

"(i) the regular percentage,

"(ii) in the case of energy property, the energy percentage, and

"(iii) the ESOP percentage.

"(B) REGULAR PERCENTAGE.—For purposes of this paragraph, the regular percentage is—

"(i) 10 percent with respect to the period beginning on January 21, 1975, and ending on December 31, 1980, or

"(ii) 7 percent with respect to the period beginning on January 1, 1981.

"(C) ENERGY PERCENTAGE.—For purposes of this paragraph, the energy percentage is—

"(i) 10 percent with respect to the period beginning on April 20, 1977, and ending on December 31, 1982, or

"(ii) zero with respect to any other period.

"(D) SPECIAL RULE FOR CERTAIN ENERGY PROPERTY.—For purposes of this paragraph, the regular percentage shall not apply to any energy property which, but for section 48(l)(1), would not be section 38 property.

"(E) ESOP PERCENTAGE.—For purposes of this paragraph, the ESOP percentage is—

"(i) with respect to the period beginning on January 21, 1975, and ending on December 31, 1980, 1 percent, and

"(ii) with respect to the period beginning on January 1, 1977, and ending on December

31, 1980, an additional percentage (not in excess of $\frac{1}{2}$ of 1 percent) which results in an amount equal to the amount determined under section 301 (e) of the Tax Reduction Act of 1975.

This subparagraph shall apply to a corporation only if it meets the requirements of section 301 (d) of the Tax Reduction Act of 1975 and only if it elects (at such time, in such form, and in such manner as the Secretary prescribes) to have this subparagraph apply."

(2) CONFORMING AMENDMENT.—Subparagraph (A) of section 46 (c) (3) (relating to public utility property) is amended to read as follows:

"(A) For the period beginning on January 1, 1981, in the case of any property which is public utility property, the amount of the qualified investment shall be $\frac{4}{7}$ of the amount determined under paragraph (1). The preceding sentence shall not apply for purposes of applying the energy percentage."

(b) DEFINITIONS AND TRANSITIONAL RULES.—Section 48 (relating to definitions and special rules) is amended by redesignating subsection (l) as subsection (n) and by inserting after subsection (k) the following new subsections:

"(l) ENERGY PROPERTY.—For purposes of this subpart—

"(1) TREATMENT AS SECTION 38 PROPERTY.—For the period beginning on April 20, 1977, and ending on December 31, 1982—

"(A) any energy property shall be treated as meeting the requirements of paragraph (1) of subsection (a), and

"(B) paragraph (3) of subsection (a) shall not apply to any energy property.

"(2) ENERGY PROPERTY DEFINED.—The term 'energy property' means property—

"(A) which is—

"(i) alternative energy property (within the meaning of section 4998(b)),

"(ii) cogeneration property installed in connection with an existing facility, but only to the extent that the cogeneration energy capacity of such facility is expanded,

"(iii) advanced technology property,

"(iv) specially defined energy property, or

"(v) recycling equipment,

"(B) which is an integral part of, or used in connection with, a building or other structure located in the United States,

"(C) (i) the construction, reconstruction, or erection of which is completed by the taxpayer after April 19, 1977, or

"(ii) which is acquired after April 19, 1977, if the original use of such property commences with the taxpayer and commences after such date, and

"(D) with respect to which depreciation (or amortization in lieu of depreciation) is allowable, and which has a useful life (determined as of the time such property is placed in service) of 3 years or more.

If any property is alternative energy property (within the meaning of section 4998 (b)), it shall not be treated as described in clause (ii), (iii), (iv), or (v) of subparagraph (A).

"(3) COGENERATION PROPERTY.—The term 'cogeneration property' means property which—

"(A) produces steam, heat, or other forms of useful energy (other than electric energy) to be used for industrial, commercial, or space heating purposes, and

"(B) also produces electric energy.

"(4) ADVANCED TECHNOLOGY PROPERTY.—The term 'advanced technology property' means equipment which uses solar, geothermal, or wind energy to provide heat, cooling, or electricity in connection with an existing building and (where applicable) an existing industrial or commercial process.

"(5) SPECIALLY DEFINED ENERGY PROPERTY.—The term 'specially defined energy property' means—

"(A) a recuperator,

"(B) a heat wheel,

"(C) a regenerator,

"(D) a heat exchanger,

"(E) a waste heat boiler,

"(F) a heat pipe,

"(G) an automatic energy control system,

"(H) a turbulator,

"(I) a preheater,

"(J) a combustible gas recovery system,

"(K) an economizer, or

"(L) any other property of a kind specified by the Secretary by regulations,

the principal purpose of which is reducing the amount of energy consumed in any existing industrial or commercial process and which is installed in connection with an existing industrial or commercial facility.

"(6) CERTAIN ADDITIONAL EQUIPMENT TREATED AS SPECIALLY DEFINED ENERGY PROPERTY.—The term 'specially defined energy property' also means—

"(A) equipment designed to modify existing facilities which use oil or natural gas as a fuel or as feedstock so such facilities will use—

"(i) a substance other than oil and natural gas, or

"(ii) oil mixed with a substance other than oil and natural gas, where such other substance will provide not less than 25 percent of the fuel or feedstock, as the case may be,

"(B) pollution control equipment installed on or in connection with equipment described in subparagraph (A), but only if such equipment meets the requirements of paragraph (3) of section 4998(b), and

"(C) fuel handling equipment necessary for the modification described in subparagraph (A), but only if such equipment is of the kind described in subparagraph (F) of section 4998(b)(1).

"(7) RECYCLING EQUIPMENT.—The term 'recycling equipment' means any equipment which is used exclusively in the recycling of solid waste or to sort and prepare solid waste for recycling.

"(8) EQUIPMENT MUST MEET CERTAIN STANDARDS TO QUALIFY UNDER PARAGRAPH (3), (4), (5), (6), OR (7).—Equipment qualifies under paragraph (3), (4), (5), (6), or (7) only if it meets the performance and quality standards which—

"(A) have been prescribed by the Secretary by regulations (after consultation with the Secretary of Energy), and

"(B) are in effect at the time of the acquisition of the property.

"(9) EXISTING.—For purposes of this subsection, the term 'existing' means—

"(A) when used in connection with a building or facility—

"(i) except as provided in clause (ii), 50 percent or more of the basis of such building or facility is attributable to construction, reconstruction, or erection before April 20, 1977, or

"(ii) which is a nuclear powerplant, a construction permit was issued and construction began before April 20, 1977, or

"(B) when used in connection with an industrial or commercial process, such process was carried on in the building or facility as of April 20, 1977.

"(10) UTILITY ALLOWED ENERGY PERCENTAGE FOR NEW BOILER ONLY TO EXTENT OIL OR GAS BOILER IS REPLACED OR PHASED DOWN.—

"(A) IN GENERAL.—In the case of a regulated public utility the principal activity of which is the production of electricity, the energy percentage shall be allowed with respect to a new boiler only to the extent that there will be a replacement or phasing-down of an old boiler which, as of April 20, 1977, used as its primary fuel oil or natural gas. The energy percentage shall be allowed with respect to a new boiler only if the taxpayer establishes such facts with respect to the replacement or phasing-down as the Secretary may by regulations prescribe.

"(B) RULES OF SECTION 4999(d) MADE APPLICABLE.—For purposes of applying subparagraph (A), the rules of paragraphs (2) through (8) of section 4999(d) shall apply, except that the term 'credit year' means only the calendar year the new boiler is placed in service.

"(11) SPECIAL RULE FOR PROPERTY FINANCED BY INDUSTRIAL DEVELOPMENT BONDS.—In the case of property which is financed in whole or in part by the proceeds of an industrial development bond (within the meaning of section 103(b)(2)) the interest on which is exempt from tax under section 103, the energy percentage shall be 5 percent.

"(12) INDUSTRIAL INCLUDES AGRICULTURAL.—The term 'industrial' includes 'agricultural'.

"(m) APPLICATION OF CERTAIN TRANSITIONAL RULES.—Where the application of any provision of subsection (a) (10) or (l) of this section or subsection (a) (2) or (c) (3) of section 46 is expressed in terms of a period, such provision shall apply only to—

"(1) property to which section 46(d) does not apply, the construction, reconstruction, or erection of which is completed by the taxpayer on or after the first day of such period, but only to the extent of the basis thereof attributable to the construction, reconstruction, or erection during such period,

"(2) property to which section 46(d) does not apply, acquired by the taxpayer during such period and placed in service by the taxpayer during such period, and

"(3) property to which section 46(d) applies, but only to the extent of the qualified investment (as determined under subsections (c) and (d) of section 46) with respect to qualified progress expenditures made during such period."

(c) ALLOWANCE OF REGULAR PERCENTAGE FOR BUSINESS INSULATION PROPERTY.—Subsection (a) of section 48 (defining section 38 property) is amended by adding at the end thereof the following new paragraph:

"(10) BUSINESS INSULATION PROPERTY.—For the period beginning on April 20, 1977, and ending on December 31, 1982, insulation shall be treated as meeting the requirements of paragraph (1) and paragraph (3) shall not apply to insulation. For purposes of the preceding sentence, the term 'insulation' means any item—

"(A) which is specifically and primarily designed to reduce when installed in or on an existing industrial or commercial building or existing industrial or commercial facility the heat loss or gain of such building or facility,

"(B) the original use of which begins with the taxpayer,

"(C) which can reasonably be expected to remain in operation for at least 3 years,

"(D) which meets the performance and quality standards which—

"(i) have been prescribed by the Secretary by regulations (after consultation with the Secretary of Energy), and

"(ii) are in effect at the time of the acquisition of the item, and

"(E) would not, but for this paragraph, be section 38 property.

For purposes of this paragraph, a building or facility will be treated as existing if it was placed in service before April 20, 1977."

(d) CREDIT FOR ALTERNATIVE ENERGY PROPERTY MAY OFFSET 100 PERCENT OF TAX LIABILITY.—Subsection (a) of section 46 is amended by adding at the end thereof the following new paragraph:

"(10) CREDIT IN CASE OF ALTERNATIVE ENERGY PROPERTY MAY OFFSET 100 PERCENT OF TAX LIABILITY.—In the case of alternative energy property—

"(A) paragraph (3)(C) shall be applied by substituting '100 percent' for '50 percent', and

"(B) the applicable percentage for purposes of paragraphs (7), (8), and (9) shall be 100 percent."

(e) DENIAL OF INVESTMENT CREDIT FOR CERTAIN ALTERNATIVE ENERGY PROPERTY.—Subsection (a) of section 48 is amended by adding at the end thereof the following new paragraph:

"(11) CERTAIN ALTERNATIVE ENERGY PROPERTY.—The term 'section 38 property' does not include any property with respect to which an election under section 4999(a) is in effect."

(f) DENIAL OF INVESTMENT TAX CREDIT FOR CERTAIN PROPERTY.—

(1) AIR CONDITIONING, SPACE HEATERS, ETC.—Subparagraph (A) of section 48(a)(1) (defining section 38 property) is amended to read as follows:

"(A) tangible personal property (other than an air conditioning or heating unit), or".

(2) BOILERS, ETC., FUELED BY OIL OR GAS.—Paragraph (1) of section 48(a) (defining section 38 property) is amended by adding at the end thereof the following new sentence: "Such term does not include any boiler or other combustor fueled by petroleum or petroleum products (including natural gas) unless the use of coal is precluded by Federal air pollution regulations or existing State air pollution regulations or unless the use of such combustor will be an exempt use within the meaning of section 4992(b)."

(3) DENIAL OF RAPID DEPRECIATION FOR BOILERS, ETC., FUELED BY OIL OR GAS.—Section 167 (relating to depreciation) is amended by redesignating subsection (p) as subsection (r) and by inserting after subsection (o) the following new subsection:

"(p) STRAIGHT LINE METHOD FOR BOILERS, ETC., FUELED BY OIL OR GAS.—In the case of any boiler or other combustor fueled by petroleum or petroleum products (including natural gas)—

"(1) subsections (b), (j), and (l) shall not apply, and

"(2) the term 'reasonable allowance' as used in subsection (a) shall mean only an allowance computed under the straight line method using a useful life equal to the class life prescribed by the Secretary under subsection (m) which is applicable to such property (determined without regard to the last sentence of subsection (m)(1)).

This paragraph shall not apply if the use of coal is precluded by Federal air pollution regulations or existing State air pollution regulations or if the use of the combustor is an exempt use within the meaning of section 4992(b)."

(4) EFFECTIVE DATE.—

(A) IN GENERAL.—The amendments made by this subsection shall apply to property which is placed in service after June 20, 1977.

(B) BINDING CONTRACTS.—The amendments made by this subsection shall not apply to property which is constructed, reconstructed, erected, or acquired pursuant to a contract which, on June 20, 1977, and at all times thereafter, was binding on the taxpayer.

(g) DEPRECIATION ALLOWANCE IN CASE OF RETIREMENT OR REPLACEMENT OF CERTAIN OIL AND GAS BOILERS, ETC.—

(1) IN GENERAL.—Section 167 is amended by inserting after subsection (p) the following new subsection:

"(q) RETIREMENT OR REPLACEMENT OF CERTAIN BOILERS, ETC., FUELED BY OIL OR GAS.—

"(1) IN GENERAL.—If—

"(A) a boiler or other combustor was in use on April 20, 1977, and as of such date the principal fuel for such combustor was petroleum or petroleum products (including natural gas), and

"(B) the taxpayer establishes to the satisfaction of the Secretary that such combustor will be retired or replaced on or before the date specified by the taxpayer,

then for the period beginning with the taxable year in which subparagraph (B) is satisfied, the term 'reasonable allowance' as used in subsection (a) includes an allowance under the straight line method using a useful life equal to the period ending with the date established under subparagraph (B).

"(2) INTEREST.—If the retirement or replacement of any combustor does not occur on or before the date referred to in paragraph (1) (B)—

"(A) this subsection shall cease to apply with respect to such combustor as of such date, and

"(B) interest at the rate determined under section 6621 on the amount of the tax benefit arising from the application of this subsection with respect to such combustor shall be due and payable for the period during which such tax benefit was available to the taxpayer and ending on the date referred to in paragraph (1) (B)."

(2) EFFECTIVE DATE.—The amendment made by paragraph (1) shall apply to taxable years ending after the date of the enactment of this Act.

PART VII—MISCELLANEOUS PROVISIONS

SEC. 2071. TREATMENT OF INTANGIBLE DRILLING COSTS FOR PURPOSES OF THE MINIMUM TAX.

Subsection (b) of section 308 of the Tax Reduction and Simplification Act of 1977 is amended by striking out ", and before January 1, 1978".

SEC. 2072. OPTION TO DEDUCT INTANGIBLE DRILLING COSTS IN THE CASE OF GEOTHERMAL DEPOSITS.

(a) IN GENERAL.—Subsection (c) of section 263 (relating to intangible drilling and development costs in the case of oil and gas wells) is amended—

(1) by adding at the end thereof the following new sentence: "Such regulations shall also grant the option to deduct as expenses intangible drilling and development costs in the case of wells drilled for any geothermal deposit (as defined in section 613(e)(2)) to the same extent and in the same manner as such expenses are deductible in the case of oil and gas wells.", and

(2) by amending the subsection heading to read as follows:

"(c) INTANGIBLE DRILLING AND DEVELOPMENT COSTS IN THE CASE OF OIL AND GAS WELLS AND GEOTHERMAL WELLS.—".

(b) MINIMUM TAX ON INTANGIBLE DRILLING COSTS IN THE CASE OF GEOTHERMAL WELLS.—

(1) Paragraph (11) of section 57(a) (relating to intangible drilling costs) is amended by striking out "oil and gas properties" each place it appears (including in the heading of subparagraph (C)) and inserting in lieu thereof "oil, gas, and geothermal properties".

(2) Clause (i) of section 57(a)(11)(B) is amended by striking out "oil and gas wells" and inserting in lieu thereof "oil, gas, and geothermal wells".

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(3) Paragraph (11) of section 57(a) is amended by adding at the end thereof the following new subparagraph:

"(D) PARAGRAPH APPLIED SEPARATELY WITH RESPECT TO GEOTHERMAL PROPERTIES AND OIL AND GAS PROPERTIES.—This paragraph shall be applied separately with respect to—

"(i) all oil and gas properties which are not described in clause (ii), and

"(ii) all properties which are geothermal deposits (as defined in section 613(e) (2))."

(4) Paragraph (2) of section 57(d) (defining straight line recovery of intangibles) is amended by adding at the end thereof the following new sentence: "This paragraph shall not apply to wells drilled for geothermal deposits (as defined in section 613(e) (2))."

(c) GAIN FROM DISPOSITION OF INTERESTS IN GEOTHERMAL WELLS.—

(1) Paragraphs (1) and (2) of section 1254(a) (relating to gain from disposition of interest in oil or gas property) are each amended by striking out "oil or gas property" each place it appears and inserting in lieu thereof "oil, gas, or geothermal property".

(2) Paragraph (3) of section 1254(a) (defining oil or gas property) is amended to read as follows:

"(3) OIL, GAS, OR GEOTHERMAL PROPERTY.—The term 'oil, gas, or geothermal property' means any property (within the meaning of section 614) with respect to which any expenditures described in paragraph (1) (A) are properly chargeable."

(3) The section heading of section 1254 is amended by striking out "**OIL OR GAS**" and inserting in lieu thereof "**OIL, GAS, OR GEOTHERMAL**".

(4) The table of sections for part IV of subchapter P of chapter 1 is amended by striking out "oil or gas" in the item relating to section 1254 and inserting in lieu thereof "oil, gas, or geothermal".

(5) Subsection (c) of section 751 (relating to unrealized receivables) is amended by striking out "oil and gas property" and inserting in lieu thereof "oil, gas, or geothermal property".

(d) APPLICATION OF AT RISK RULES TO GEOTHERMAL DEPOSITS.—

(1) Paragraph (1) of section 465(c) (defining activities to which at risk rules apply) is amended by striking out "or" at the end of subparagraph (C), by adding ", or" at the end of subparagraph (D), and by

inserting after subparagraph (D) the following new subparagraph:

"(E) exploring for, or exploiting, geothermal deposits (as defined in section 613 (e) (2))".

(2) Paragraph (2) of section 465 (c) is amended by striking out "or" at the end of subparagraph (C), by adding "or" at the end of subparagraph (D), and by inserting after subparagraph (D) the following new subparagraph:

"(E) geothermal property (as determined under section 614),".

(e) EFFECTIVE DATE.—

(1) IN GENERAL.—The amendments made by this section shall apply with respect to wells commenced on or after April 20, 1977, in taxable years ending on or after such date.

(2) ELECTION.—The taxpayer may elect to capitalize or deduct any costs to which section 263 (c) of the Internal Revenue Code of 1954 applies by reason of the amendments made by this section. Any such election shall be made before the expiration of the time for filing claim for credit or refund of any overpayment of tax imposed by chapter 1 of such Code with respect to the taxpayer's first taxable year to which the amendments made by this section apply

and for which he pays or incurs costs to which such section 263 (c) applies by reason of the amendments made by this section. Any election under this paragraph may be changed or revoked at any time before the expiration of the time referred to in the preceding sentence, but after the expiration of such time such election may not be changed or revoked.

SEC. 2078. 10-PERCENT DEPLETION IN THE CASE OF GEOTHERMAL DEPOSITS.

(a) GENERAL RULE.—Paragraph (4) of section 613 (b) (relating to 10-percent depletion rate) is amended by striking out "and wollastonite" and inserting in lieu thereof "wollastonite, and geothermal deposits".

(b) LIMITATIONS.—Section 613 (relating to percentage depletion) is amended by adding at the end thereof the following new subsection:

"(e) SPECIAL RULES FOR GEOTHERMAL DEPOSITS.—

"(1) PERCENTAGE DEPLETION MAY NOT EXCEED ADJUSTED BASIS OF PROPERTY.—In the case of each property which is a geothermal deposit, the allowance for depletion determined under this section for any taxable year shall not exceed the adjusted basis (for purposes of determining gain) of such property as of the end of such taxable year (determined without regard to any deduction for depletion for the taxable year).

"(2) GEOTHERMAL DEPOSIT DEFINED.—For purposes of this section, the term 'geothermal deposit' means a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure)."

(c) TECHNICAL AMENDMENTS.—

(1) Paragraph (1) of section 613(c) (defining gross income from the property) is amended by inserting "and other than a geothermal deposit" after "oil or gas well".

(2) Subsection (d) of section 613 is amended by adding at the end thereof the following new sentence: "The preceding sentence shall not apply to any geothermal deposit."

(3) Paragraph (1) of section 613A(b) is amended—

(A) by inserting "and" at the end of subparagraph (A),

(B) by striking out "and" at the end of subparagraph (B), and

(C) by striking out subparagraph (C).

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 1977.

SEC. 2074. REREFINED LUBRICATING OIL.

(a) IN GENERAL.—Section 4093 (relating to exemption of sales to producers) is amended to read as follows:

"SEC. 4093. EXEMPTIONS.

"(a) SALES TO MANUFACTURERS OR PRODUCERS FOR RESALE.—Under regulations prescribed by the Secretary, no tax shall be imposed by section 4091 on lubricating oils sold to a manufacturer or producer of lubricating oils for resale by him.

"(b) USE IN PRODUCING REREFINED OIL.—

"(1) SALES TO REREFINERS.—Under regulations prescribed by the Secretary, no tax shall be imposed by section 4091 on lubricating oil sold for use in mixing with used or waste lubricating oil which has been cleaned, renovated, or rerefined. Any person to whom lubricating oil is sold tax-free under this paragraph shall be treated as the producer of such lubricating oil.

"(2) USE IN PRODUCING REREFINED OIL.—Under regulations prescribed by the Secretary, no tax shall be imposed by section 4091 on lubricating oil used in producing rerefined oil to the extent that the amount of such lubricating oil does not exceed 55 percent of such rerefined oil.

"(3) REREFINED OIL DEFINED.—For purposes of this subsection, the term 'rerefined oil' means oil 25 percent or more of which is used or waste lubricating oil which has been cleaned, renovated, or rerefined."

(b) CONFORMING AMENDMENT.—Section 4092 (a) is amended by striking out "4093" and inserting in lieu thereof "4093 (a)".

(c) CLERICAL AMENDMENT.—The table of sections for subpart B of part III of subchapter A of chapter 32 is amended by striking out the item relating to section 4093 and inserting in lieu thereof the following:

"Sec. 4093. Exemptions."

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to sales on or after the first day of the first calendar month beginning more than 10 days after the date of the enactment of this Act.

SEC. 2075. ANNUAL REPORT ON ENERGY AND REVENUE EFFECTS OF THIS TITLE.

During August of each calendar year beginning after 1977, the President shall submit a report to the Congress which shall contain the following information:

(1) The amount of the increases or decreases in the revenues received in the Treasury during periods before the submission of such report resulting from each of the provisions of this title.

(2) An evaluation of the extent to which each of the provisions of this title resulted in increased energy conservation and production.

(3) Such other information as the President may determine to be relevant for an evaluation of the provisions of this title.

PART VIII—CONGRESSIONAL PROCEDURES FOR EITHER HOUSE VETO

SEC. 2061. CONGRESSIONAL PROCEDURES FOR EITHER HOUSE VETO OF CERTAIN SUSPENSIONS WITH RESPECT TO ENERGY EXCISE TAXES.

(a) SUBMISSION TO CONGRESS.—Whenever the President submits a suspension plan under section 4987 (d) (1) or 4991 (b) of the Internal Revenue Code of 1954 to the Congress, a copy of such plan shall—

(1) be delivered to each House of Congress on the same day and shall be delivered to the Clerk of the House of Representatives if the House is not in session and to the Secretary of the Senate if the Senate is not in session, and

(2) bear an identification number.

(b) PROCEDURES FOR DISAPPROVAL.—

(1) IN GENERAL.—The House of Representatives or the Senate may disapprove any suspension plan referred to in subsection (a) if it adopts a resolution of disapproval—

(A) by an affirmative vote of the majority of those present and voting in that House, and

(B) before the close of the 15th day after the date on which such plan was delivered to the Congress under subsection (a).

(2) RESOLUTION OF DISAPPROVAL.—For purposes of this section, the term "resolution of disapproval" means only a resolution of either House of Congress, the matter after the resolving clause of which is as follows: "That the   does not favor the taking effect of the proposed suspension plan numbered   , transmitted to the Congress by the President on   ", the first blank space therein being filled with the name of the resolving House and the other blank spaces being appropriately filled.

(c) PROCEDURE IN EACH HOUSE.—

(1) A resolution of disapproval in the House of Representatives shall be referred to the Committee on Ways and Means. A resolution of disapproval in the Senate shall be referred to the Committee on Finance.

(2) (A) If the committee to which a resolution of disapproval with respect to any suspension plan has been referred has not reported it before the close of 7 days after its introduction, it is in order to move either to discharge the committee from further consideration of the resolution or to discharge the committee from further consideration of any other resolution of disapproval

with respect to such plan which has been referred to the committee.

(B) A motion to discharge may be made only by an individual favoring the resolution, is highly privileged (except that it may not be made after the committee has reported a resolution of disapproval), and debate thereon shall be limited to not more than 1 hour, to be divided equally between those favoring and those opposing the resolution. An amendment to the motion is not in order, and it is not in order to move to reconsider the vote by which the motion is agreed to or disagreed to.

(C) If the motion to discharge is agreed to or disagreed to, the motion may not be renewed, nor may another motion to discharge the committee be made with respect to any other resolution of disapproval with respect to the same suspension plan.

(3) (A) When the committee has reported, or has been discharged from further consideration of, a resolution of disapproval, it is at any time thereafter in order (even though a previous motion to the same effect has been disagreed to) to move to proceed to the consideration of the resolution. The motion is highly privileged and is not debatable. An amendment to the motion is not in order, and it is not in order to move to reconsider

the vote by which the motion is agreed to or disagreed to.

(B) Debate on the resolution of disapproval shall be limited to not more than 10 hours, which shall be divided equally between those favoring and those opposing the resolution. A motion further to limit debate is not debatable. An amendment to, or motion to recommit, the resolution is not in order, and it is not in order to move to reconsider the vote by which the resolution is agreed to or disagreed to.

(4) (A) Motions to postpone, made with respect to the discharge from committee or the consideration of a resolution of disapproval, and motions to proceed to the consideration of other business, shall be decided without debate.

(B) Appeals from the decisions of the Chair relating to the application of the Rules of the House of Representatives or the Senate, as the case may be, to the procedure relating to any resolution of disapproval shall be decided without debate.

(5) (A) As used in subsections (b) (1) (B) and (c) (2) (A), the term "day" means any calendar day other than a day on which either House is not in session because of a sine die adjournment or an adjournment of more than 3 days to a day certain.

(B) For purposes of this section, if any suspension plan is delivered to the Congress on any day on which either House is not in session, such plan shall be treated as delivered on the first day thereafter on which both Houses are in session.

(6) This subsection is enacted by the Congress—

(A) as an exercise of the rulemaking power of the House of Representatives and the Senate, respectively, and as such it is deemed a part of the rules of each House, respectively, but applicable only with respect to the procedure to be followed in that House in the case of resolutions of disapproval; and they supersede other rules only to the extent that they are inconsistent therewith; and

(B) with full recognition of the constitutional right of either House to change the rules (so far as relating to the procedures of that House) at any time, in the same manner, and to the same extent as in the case of any other rule of that House.

Passed the House of Representatives August 5, 1977.

Attest:

Clerk.

Appendix B—Responses From the Department of the Treasury of Questions Asked by Members of the Committee on Finance

Response to Senator Roth's Question on Additional Unemployment Attributable to Administration Energy Program

During Secretary Blumenthal's testimony before the Senate Finance Committee on August 9, 1977, Senator Roth referred to forecasts of unemployment attributable to the Administration energy program (Transcript, page 37.) Senator Roth cited one of the pamphlets prepared by the Joint Committee on Taxation as the source for his statement that the Administration estimated that its own energy program would produce 200,000 additional unemployment.

The source referred to by Senator Roth is Pamphlet No. 6, "Economic and Budget Considerations," prepared for the Committee on Ways and Means by the staff of the Joint Committee on Taxation, June 3, 1977, at page 12. Here it is indicated that the Administration estimates that the Energy Plan would increase unemployment by 0.2 percentage points (200,000 workers) above the rate without the Energy Plan.

During the Ways and Means consideration of the Energy bill, it was indicated by the Administration that this figure was a printing error, and that the projected increase in unemployment as predicted by the Administration should be zero. As stated on page 11 of Pamphlet No. 6: "The Administration . . . expects the program to have no impact on real GNP or employment, although it acknowledges that such estimates are uncertain and that there could be modest positive or negative impact."

Question. What is it going to cost for the U.S. to reach energy sufficiency? How are we going to raise the money? Where is the money going to come from; the banking system, a lot of new investment? How do you expect to get them in there?

Then how many years would it take us to reach sufficiency if we would do it?

Answer. Since the Administration has not proposed to achieve energy sufficiency, it has not prepared an analyses of the costs. Most experts agree that the achievement of total energy self-sufficiency would involve either drastic cutbacks in levels of energy consumption and marked reduction in our standard of living or the use of unproven technologies. (See letter).

Question. What is the estimated cost to industry if the Administration's program is fully carried out to convert to the use of coal?

Answer. Through 1985 we estimate that industry will spend $33 billion in converting to coal. These expenditures will be financed through rebate of oil and gas taxes and will achieve the Administration's target for coal conversion.

Question. Can oil be made out of coal for a lower cost than it can be made out of shale?

Answer. No. ERDA presently estimates that it would cost $15 to $20 per barrel to produce oil from shale and $20 to $30 to produce oil from coal.

Question. Are there any estimates of the cost required to achieve energy independence?

Answer. No, there are no current studies directed to the question of the cost of achieving energy independence. There have been several earlier studies directed at the question of how the United States could decrease its dependence on foreign sourcs of oil by 1985 but no reputable study that addressed the question of complete self-sufficiency.

In November, 1974, FEA released its Project Independence report which estimated the required increase in the domestic energy production to keep imported petroleum at about ⅓ of total supply.

The National Energy Outlook put out by FEA in January 1976 prepared estimates of the kind of policies and programs necessary to reduce oil imports in 1985 to between 2.5 and 6.0 million barrels a day. To achieve the lower level of 2.5 million barrels would involve drastic conservation measures and cut backs in domestic consumption as well as complete decontrol of prices and other incentives to increase investment in domestic energy production.

Question. What would it cost to solve "this problem" using coal and using shale?

Answer. It is impossible to answer the question as to the cost of achieving energy sufficiency using coal or using shale at this time for several reasons. While we can estimate the conversion costs per barrel based on a limited operation, we do not know whether we have adequate resources, such as water in the proper location, to implement these technologies at the scale required to achieve sufficiency. In addition, the environmental impacts of large scale conversion are unknown.

RESPONSE TO SENATOR MATSUNAGA CONCERNING THE DEPARTMENT OF ENERGY BUDGET FOR ENERGY RESEARCH AND DEVELOPMENT

The Department of Energy Budget for all Energy research and development (which includes contract work, pilot plants and demonstration projects) is as follows for the period 1976–1978[1]:

	Billions
1976	$1,657
1977	2.600
1978	3.069

Of this total the following amounts have been allocated to research in areas in which the Committee has expressed an interest—the development of oil shale, coal gasification, methane and geothermal:

	Millions
Oil shale:	
1976	$15.8
1977	22.8
1978	28.9
Coal gasification:	
1976	84
1977	112.8
1978	206.5
Methane from coal:	
1976	0
1977	0
1978	3.5
Geothermal:	
1976	31
1977	55
1978	101
Solar:	
1976	115
1977	290
1978	320

[1] The 1978 figures represent the President's budget figures.

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