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DEPENDENCE ON FOREIGN OIL

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY AND AGRICULTURAL TAXATION

OF THE

COMMITTEE ON FINANCE
UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

SECOND SESSION

JULY 27, 1990

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DEPENDENCE ON FOREIGN OIL

FRIDAY, JULY 27, 1990

U.S. SENATE,
SUBCOMMITTEE ON ENERGY AND AGRICULTURAL TAXATION,
COMMITTEE ON FINANCE,
Washington, DC.

The hearing was convened, pursuant to notice, at 10:40 a.m., in room SD-215, Dirksen Senate Office Building, Hon. David L. Boren (chairman of the subcommittee) presiding.

Also present: Senator Lloyd Bentsen.

[The press release announcing the hearing follows:]

[Press Release No. H-46, July 19, 1990]

SUBCOMMITTEE TO EXAMINE DEPENDENCE ON FOREIGN OIL; STEPS TO INCREASE DOMESTIC ENERGY PRODUCTION AND RESERVES TO BE EXPLORED

WASHINGTON, DC.—Senator David L. Boren (D., Oklahoma), Chairman, announced Thursday the Finance Subcommittee on Energy and Agricultural Taxation will hold a hearing on the United States' growing dependence on foreign energy imports and on steps that can be taken to increase domestic energy production and reserves.

The hearing is scheduled for *Friday, July 27, 1990 at 10 a.m.* in Room SD-215 of the Dirksen Senate Office Building.

"With imported oil at dangerously high levels, especially coming from countries around the volatile Persian Gulf, we cannot afford to wait any longer. In Oklahoma alone we have lost 85 percent of our operating rigs in the last 8 years due to the drastic drop in oil prices," Boren said.

"It is my hope that this hearing will focus on the specific steps we must take to boost domestic energy production and add to our rapidly depleting domestic reserves," Boren said.

OPENING STATEMENT OF HON. DAVID L. BOREN, A U.S. SENATOR FROM OKLAHOMA, CHAIRMAN OF THE SUBCOMMITTEE

Senator BOREN. Let me start out by thanking our witnesses today. We have two votes on the floor that were supposed to have completed by 10:20, but as usual the roll call went on a little longer so we were delayed in getting started. I know some other members are planning to attend this morning. They are undoubtedly on their way over, but I will begin the proceedings. I know that they will get here hopefully in time to hear the witnesses, but they will not be too downhearted if they miss my opening statement. So we will begin and commence at that point today.

I have called this hearing today to once again examine the dramatic and continuing decline of U.S. energy production. This is not the first time this committee has addressed this issue. I have been sounding the call, as have other members of this committee for a clear and practical energy policy, including domestic production incentives, since I came to the Senate in 1979.

Let's just review for a moment what happened just since 1985. The number of rotary rigs operating in the United States has declined from an average of 1,980 in 1985 to an average of 952 through the first 6 months of 1990. This is indicated here on the chart which indicates what is happening to the level of rig activity. This is over a 50-percent decline in less than 5 years. And, of course, if we go back to 1982 the decline is much more dramatic because in 1982 we had over 4,700 rigs operating in the United States. The decline since 1982 has been 80 percent. There are fewer rigs looking for new domestic reserves of oil and gas.

In fact, 1989 was the lowest average rig count since World War II. How does the declining rig count affect our energy security? One look at imports as a percentage of the total U.S. petroleum consumption can answer that question. The United States is now importing over 52 percent of our petroleum needs. For the first time in our Nation's history we are importing more energy from abroad than we are producing here at home. Imports today are higher than during both the Iranian crisis in 1979 or the Arab oil embargo in 1973. Yet yet no one seems concerned.

For example, when was the last time anyone in this room saw an advertisement for a car that emphasized strongly the point of fuel economy. Then there are those who suggest that rising imports do not matter. They say that we are not likely to see in the 1990's supply disruptions like we saw during the 1970's.

Well where do our imports come from? Since 1985 imports from Persian Gulf producers have increased 450 percent. I want to say that again. Since 1985 imports from the Persian Gulf region have gone up 450 percent. Today almost 25 percent of our oil imports come from Arab OPEC countries. Haven't we learned anything from the experience of the 1970's? If anyone doubts our energy security is threatened they need only look to the events of just this past week.

While Iraq, with a total military force in excess of 1 million people has massed its forces along the Kuwait border the price of crude oil has changed $5, going up $5, within a 2-week period. Here we are with a 450-percent increase in our dependence on oil from this part of the world. What would happen to the price of oil and all energy if the situation erupted into a shooting war?

Let me say from my perspective as chairman of the Intelligence Committee I have been following this matter very, very closely. I do not think we are facing just a short-term problem of instability in this region. When you have a military force the size of that of Iraq's, and when they have demonstrated a willingness to use that military force and use it as a club to try to dictate oil pricing decisions, I think we are in for a long period of tension and instability in this region of the world as it affects oil production.

What would happen if Iraq did not stop with Kuwait but continued south to challenge the united Arab immigrants or possibly even to challenge Saudi Arabia? When will we take the steps necessary to preserve some measure of domestic energy production to protect our national security interests?

I have long advocated price stability as an essential element of any national energy policy. I have in the past introduced legislation that will establish a variable import fee to be assessed on all imported oil. More recently I have proposed a flexible floor initiative that would provide incentives for domestic producers if the world price of crude fell below certain levels.

Specifically this proposal would do the following: First, enact a production credit for marginal wells equal to 1 percent of the cost of production for every $1 the world price of crude fell below $22 per barrel. For example, if the world price was $15 per barrel a 7-percent credit would apply. The credit would be fully creditable against the alternative minimum tax.

Second, suspended tangible drilling costs and percentage depletion as preference items for the alternative minimum tax when the world price of crude oil is below $22 per barrel.

And third, provide a variable percentage depletion rate tied to the world price of crude oil. When the price of crude oil is over $22 the depletion rate would remain at 15 percent. When the price of oil is below $22 the depletion rate would phase up to as high as 30 percent; thereby providing a kind of support floor in cases where prices become very, very unstable.

We have to realize that one of the things holding back the domestic energy from producing more is not just the price level, it is also the uncertainty about where prices are going. In our region of the country where the financial sector has been so hard hit, financial institutions are simply afraid to make loans to independent oil producers, for example, because they do not know where oil prices are going next. So it is not only an adequate price, it is a stable price for oil that is essential. By adopting a sliding scale of tax incentives as prices fluctuate we can help minimize the level of fluctuation in terms of the actual cash flow to the producer.

The fact remains we must take steps now to preserve what is left of our domestic energy industry. During the past 7 years over 6,000 oil and gas operators have gone out of business and closed their doors. But for the domestic decline in price of crude oil in 1986-87, we might not have had the crisis in the financial industry that we have had. We must come to the realization that cheap energy today will ultimately exact a terrible cost to our economy in the future.

One estimate of our energy trade imbalance provided by this committee by Dr. Jess Koontz, vice president for economic analysis at the Grace Energy Corp., shows that the cost of oil imports could rise to $97 billion a year in 1995. We can only imagine what the price of these imports would be if oil recovered to earlier price levels. We could completely close out the trade imbalances in all other sectors with all other countries—the merchandise imbalance, the service imbalance. If we continued to import this escalating percentage of our oil needs, we could have a trade imbalance larger than we have now due only to the importation of petroleum products.

As we worry about the impact of our national debt on our children and our grandchildren, and this external debt, we must worry about the future burden of our failure to establish a national energy policy today, but to preserve our domestic energy industry.

I look forward to hearing from our witnesses today. I know that they will offer words of encouragement and advice. I only hope that our colleagues in the entire Senate will heed this advice. For once let's not sit here until the crisis actually erupts. Let us realize that we have a dire threat to our national security because of our growing dependence upon imports.

We are going to wake up one of these days when trouble erupts. We see all too clearly the possibility of that trouble from the events that are going on in the Middle East right now. We are going to find that we have not trained the new generation. The number of students going into petroleum engineering and to geology and related fields is at an all time low.

I was told just yesterday by one of the officials at the University of Oklahoma that in one essential graduate program in geology at the University, they now only have one student. They have only 15 new students in one of the basic undergraduate majors where we have had hundreds of students in the past. We are destroying the ability of this industry to respond to a crisis in the future and we are on the road to creating that crisis by our own inaction.

I see that we have been joined by the distinguished chairman of the Finance Committee, Senator Bentsen. Again and again, he has been one of those that has sounded the alarm. No one in the country has spoken more forcefully on this issue than he has. His peril point legislation and many other proposals that he has made in the past have really charted the course of what should have been done. We would not be in the situation that we now face; we would not have this threat to our national security, if policymakers both in the administration and Congress had listened to what Senator Bentsen had to say in earlier periods of time.

So I am very pleased he has joined us; and I would like to recognize him for any remarks that he might like to make.

[The prepared statement of Senator Boren appears in the appendix.]

OPENING STATEMENT OF HON. LLOYD BENTSEN, A U.S. SENATOR FROM TEXAS, CHAIRMAN, SENATE FINANCE COMMITTEE

The CHAIRMAN. Thank you very much, Mr. Chairman. Senator Boren has been a great ally in working on the problem of developing energy self-sufficiency in this country. He has been a leader in that field. He has already done a good job of explaining the problem and some of the available options, so I will put most of my comments in the record.

I will have to return to the floor of the Senate again this morning, as I did last night, to face one of those issues that Senator Boren alluded to. That is the problem posed by a dictator, a ruler, like Saddam Hussein in Iraq. Here is a man with almost a million people under arms. He has the most powerful military machine in that part of the world; he is a man who has had a record of brutality, of using that muscle, and he is now doing it against Kuwait. There is no question in my mind that his target is not just Kuwait, but it is Saudi Arabia too.

Now can you imagine what would happen to this country if that man gets control of those energy supplies; what it would mean to the national security of our country; what it would mean to the trade imbalance? Today, of the $108 billion in the merchandise trade deficit, we see approximately $40 billion of that deficit charged to net oil imports. And the way the situation is headed this year, the portion of the trade deficit that is attributable to net oil imports will probably rise to 50 percent.

As the chairman was stating earlier, I sponsored legislation called the "peril point" legislation. Some interpreted that to mean an import fee on oil—not necessarily so at all. What I was calling for was an energy policy in this country to help develop some energy self-sufficiency, and to reduce our dependence on Middle East oil.

I was visiting with some of the top officials in Japan the year before last talking to them about various problems facing our nations. And they were talking about our budget deficit. I said to them that it is an interesting thing, that if we spent on our defense what they spent on their defense as a percentage of their gross domestic production—if we spent just that 1 percent—we would have a balanced budget. But I sure do not advocate that: I tell you what you would have, you would have chaos. That's because 53 percent of their oil comes from the Persian Gulf, and if they had not had the U.S. Navy in there to break that blockade their entire economy would have come apart. And that would have affected all of the democracies of the world because everyone would have been fighting for what little was left in the way of energy to import.

Oh, I know, some of my friends say well if we raise the price of oil to $50 per barrel how much better off we would be. But when you are seeing the kind of energy dependence we have and what it is doing to our trade deficits and seeing us move from the number one creditor nation in the world to the number one debtor nation in just 3 years, it becomes apparent how important it is for us to have some incentives for domestic production of oil and gas in this country, to lessen that kind of dependence.

That is why I am glad that Senator Boren has called this hearing—to try to get input from you folks as to what we can do to encourage oil and gas production in this country and lessen that kind of dependence. When I was talking about "peril point," I was just talking about a President addressing the many facets of this problem, addressing all of them—incentives, conservation, and those types of things that would make us more independent in this kind of a situation.

I do not know how you can dramatize it anymore than what is happening in the Middle East right now. I do not know what more it takes to make us act short of waiting for an absolute crisis in our country.

Mr. Chairman, I am sorry I cannot stay here because I have to get back to the floor on that amendment and try to address the very problem we are talking about.

Thank you very much.

Senator BOREN. Thank you very much, Mr. Chairman. We appreciate your being here and we appreciate the leadership that you have given on this issue. I just hope before this session of Congress and the work for this year is completed that we will be able to do something positive to encourage domestic production and try to make us less insecure as a nation because of our failure to have a national energy policy.

Thank you very much for joining us.

The CHAIRMAN. Thank you.

Senator BOREN. Is Senator Akaka here yet? I know he is on his way. Senator Domenici is in another hearing. So I believe we will just proceed with Mr. Robert Wootton, Tax Legislative Counsel, Office of the Assistant Secretary for Tax Policy, representing Treasury.

Mr. Wootton, we are very happy to have you with us this morning. We would invite you, if you wish, to summarize your statement in any way you would like to and we will certainly put your entire statement into the record. We welcome you to the committee.

STATEMENT OF ROBERT R. WOOTTON, TAX LEGISLATIVE COUNSEL, OFFICE OF THE ASSISTANT SECRETARY FOR TAX POLICY, U.S. TREASURY

Mr. WOOTTON. Thank you very much, Mr. Chairman. I am pleased to be here today to have the opportunity to discuss the views of the Treasury Department on an issue that is of concern to us all, the steps that can be taken to enhance domestic energy production and reserves, and to do that in a manner that is consistent with maintaining the current budgetary restraints within which we all must live.

We are confronted at the outset by two facts. First, domestic energy production is declining—according to Energy Department estimates, by about 15 percent from 1986 to the present time. And as you indicated in your opening remarks, Mr. Chairman, the rig count and other measures of oil production can be much more dramatic than overall production.

The second fact that confronts us is that the reality of the current budget environment requires that every proposal that we consider to address this situation must be evaluated in accordance with its cost and its cost effectiveness. The administration believes that tax incentives can and should be used to enhance our Nation's energy production. We believe that the administration's budget proposals which were made in the fiscal year 1990 budget and also the fiscal year 1991 budget will offer real help in meeting energy independence goals within the constraints of responsible fiscal policy.

The administration's budget proposals are constructed around two themes or policy objectives. The first is enhancing exploratory drilling activities. This we believe will lead to new discoveries of oil and gas. It will increase the level of proven domestic reserves and allow ultimately for growth in long-term domestic energy production.

The second theme in the administration's budget proposals is to sustain and improve production for mature and marginal oil and gas properties. This should have an immediate impact in terms of increasing production. Perhaps even more important, it will help to preserve the industry infrastructure that the Nation needs to meet our energy needs.

I would like to take up each of these two themes in turn. First to exploratory drilling. The administration proposes two tax incentives to encourage exploratory drilling. These are discussed, Mr. Chairman, in some detail in my written statement and with your permission I will summarize them here.

First, we propose a tax credit for intangible drilling costs related to exploratory drilling. The tax credit available to any given taxpayer would drop from 10 percent to 5 percent after the first $10 million of expenditures each year and would be phased out if the average daily U.S. well-head price of oil equals or exceeds $21 a barrel.

Second, we propose to eliminate 80 percent of the current AMT preference arising from exploratory IDC's—intangible drilling costs. This proposal would apply to independent producers only. Independent producers historically have engaged in a disproportionate amount of exploratory drilling and many are currently subject to the AMT. Restoring to these taxpayers the full value of current deductions for most exploratory IDC's snould provide a real incentive for them to undertake exploratory drilling at an acceptable cost in terms of foregone tax revenues.

Now to the second theme, marginal properties. Our proposals for enhancing production from marginal properties are contained in three budget initiatives. Once again I would like to summarize.

The first proposal is a 10-percent credit for all capital expenditures on new applications of tertiary enhanced recovery techniques to producing properties. Like the drilling credit, this one would phase out if the oil price goes above $21 a barrel.

Second, we would eliminate the so-called transfer rule, which in most cases prevents the transferee of a proven oil or gas property from claiming percentage depletion. The rationale originally offered for the transfer rule was to prevent integrated producers indirectly from benefiting from percentage depletion by selling proven properties to independent producers.

However, the transfer rule applies equally to transfers of properties among independents in situations where the transferor would itself qualify for claiming percentage depletion. In addition, the transfer rule creates a disincentive for the transfer of marginal properties to those who, because of specialized expertise, operating efficiencies or other factors, would be more likely to keep property in production.

Finally, the administration proposes to raise the percentage depletion deduction limit for independent producers and royalty owners. Under the so-called net income limitation of current law, percentage depletion is limited to 50 percent of the taxable income from the property. This restriction is most likely to affect marginal properties where operating costs are high relative to revenues.

We propose to encourage continuing production from these marginal properties, the so-called stripper wells, by increasing the net income limitation from its current 50 percent to 100 percent.

Mr. Chairman, we believe as a package that these five budget proposals are a cost effective means of stimulating exploratory drilling and preserving marginal and tertiary production. We look forward to working with the subcommittee, the full committee and the Congress in enacting legislation consistent with sound fiscal policy to meet our Nation's energy needs.

I appreciate the opportunity to be here today and I would be happy to try to answer questions at this time.

[The prepared statement of Mr. Wootton appears in the appendix.]

Senator BOREN. Thank you very much, Mr. Wootton, how has the OMB and CBO scored the cost of the package of incentives which the administration is supporting?

Mr. WOOTTON. The overall cost is in the $400 to $500 million a year range, Mr. Chairman. I can break that out if you would like between the various proposals.

Senator BOREN. No, that is fine. I am just wondering about the overall figure. Is the administration committed to these proposals? We are of course now in the midst of Budget Summit negotiations and we will be facing a whole package on the budget. I for one am very concerned because as we know from the past we have had some of these proposals. We have not been able to successfully get them enacted into law because, of course, every time we have any kind of an incentive where those have scored for budget purposes I think sometimes incorrectly because I do not think they always take into account the dynamic economic growth that is going to occur in all forms of revenues as a result of incentives.

I certainly do not accurately count the cost of relying upon imports as an offset against having this production domestically and what it does to the trade imbalance. But we live under rules, right or wrong, that require these revenue offsets. So it has made it very, very difficult when you have been dealing with very, very small budgetary packages to get these changes adopted.

Is it your feeling that this year the administration as we look at coming with a relatively large budget package obviously to try to deal with the current fiscal crisis at the Budget Summit meeting, that the administration will push very hard in the hours of these negotiations to include a package of meaningful incentives to encourage domestic energy production in the final budget package?

Mr. WOOTTON. Yes, Senator, that is my feeling. The administration continues to support the budget proposals and in particular the proposals relating to the production of energy.

Senator BOREN. Well I think it is very important that we have that support and that we have it strongly. There are a number of us here on this committee that will be working to that end as well.

I noticed that in your proposal on enhanced recovery that you phase out the credit at $21 a barrel. S. 828 which Senator Domenici and I have introduced follows a similar approach really on enhanced recovery; however, we do not phase out those credits until $30 a barrel. Do you think that the response especially on marginal production will be sufficient if we phase them out as low as $21 a barrel?

Mr. WOOTTON. Well, this is a matter for—if I may say—fine tuning and debate when we are closer to the time. The administration's proposals were put together awhile ago and it may be that closer to the time, with a view to the cost of proposals, the Congress might choose to use a different figure.

Senator BOREN. What you are saying is there is nothing magic about the $21 figure, and that figure is something to look at within the bounds of revenue availabilities?

Mr. WOOTTON. Yes, the magic of the number is, of course, the higher it is the more costly it is.

Senator BOREN. In looking at your proposal on the tax credit for exploratory drilling, how broadly will the term "exploratory" be defined in this context? Will it be defined broadly enough to include drilling conducted by producers in relatively mature oil and gas fields?

Mr. WOOTTON. We have been doing continuing staff work over the past year on the various technical issues that are involved in fleshing out the administration's proposal. The principal reason, we think, for increased tax incentives for exploratory work is the degree of risk that it entails, in that the market all by itself may not promote the appropriate amount of risk taking in that area.

It seems that the question you asked would be resolved in principal by reference to the amount of risk involved. If there were viable amounts of commercial production continuing on the property, one would think that the exploratory credit in the administration's proposal would not be available.

Senator BOREN. I understand what you are saying, but I think we also again have to understand that instability in oil prices itself creates a very high level of risk, even in fields that are relatively mature. So that certainly with a wild cat well you have both things coming into play. You have the highest possible level of risk in a new area. We are not certain about reserves as compared to more mature fields. I would urge that you keep in mind also, looking at the instability of price over the last several years, that we consider a concept of risk because that can be what determines whether or not someone is going to undertake to drill a well. Really, the bottom line is the likelihood, not only the likelihood of finding the oil but the likelihood that the revenue from the oil found will repay the debt undertaken to make that decision. So I think we have to consider that as well.

I am sure you are aware of the GAO report which has been issued which I must say I am shocked. I think that they seem to downplay and not believe that there is much serious level of risk because of our increasing dependence on foreign oil. Surely they have come to those conclusions without the benefit of any kind of information from the intelligence community and certainly without assessing risks in the Middle East. Certainly they must have come to it without any knowledge of decisions that were going to be made by Iraq military forces in the last few days.

But they also assert that the tax credit proposals from the administration, as well as those proposals that have been made by myself, members of this committee, Congressman Andrews who I see has just come into the room, and others, they have attacked those for being inefficient in the way of encouraging domestic energy production.

Has Treasury assessed this report and has Treasury expressed any opinion about the GAO report?

Mr. WOOTTON. We were given an opportunity, Mr. Chairman, to review the report in a draft stage some months ago. The Treasury

Department did indeed write a letter to the GAO commenting on some aspects of the draft report.

If you would like, I brought a copy of the letter with me and can offer it to the record at this time.

Senator BOREN. I'd be happy to insert that in the record without objection at this point.

[The letter appears in the appendix.]

Senator BOREN. You might just summarize at least the highlights of what Treasury had to say.

Mr. WOOTTON. Well, from the point of view of a Treasury bean counter, I am not going to look at the effect of the proposals on international relations and so forth. But I would like to raise my sights just a bit. It seems that the GAO report focuses generally on increases in current production as the measure of cost effectiveness. That certainly is one measure.

In the letter which we wrote to GAO, the administration tried to take into account longer term benefits as well that might be harder to quantify. For example, a major intention of our various incentives for tertiary recovery is to stimulate the development of new recovery methods and technologies. DOE estimates, I believe, that only about a third of the oil in a normal reserve is recovered, the remaining two-thirds being left in the ground. Obviously enhancements in tertiary production techniques could lead to great increases in proven reserves.

Similarly, the administration's proposals to keep marginal properties on line and producing would do a number of things that are hard to quantify. Obviously, they would tend to keep improving the financial health of independent producers who traditionally have undertaken most of the exploratory work.

Also, we feel that keeping marginal wells in production is very important in terms of maintaining the industry infrastructure. And there we mean not only the pool of skilled technicians and the like, but also another important part of the industry infrastructure, the wells themselves. When a well is shut in and permanently cemented, the reserves that are there are gone, absent redrilling. To the extent that marginal properties economically can be kept on line, that potential reserve is maintained, and an ability to tap it in the future is also maintained.

On a bit more technical level, I would like to make one note. I note that the GAO report went to press prior to receiving estimates of production increases resulting from either of the tax credits in the administration's budget. Consequently the GAO report estimates total increases in production arising from the budget proposals of 25,000 to 40,000 barrels a day, but this is without estimating the production increases from either the exploratory credit or the tertiary credit.

I believe taking those two into account that DOE's current estimates are about five times the GAO's estimates. I presume that Mr. Stagliano from the Department of Energy would be available to address that point more fully.

Senator BOREN. Thank you very much.

Last fall during the budget reconciliation process I had prepared some legislation to clarify the definition of tar sands under the Internal Revenue Code, Section 29, by inserting the Department of

Energy definition at that time into the Code. During the full committee mark-up on that reconciliation bill the Deputy Assistant Secretary of Tax Policy, Dana Trier, requested that I defer offering this amendment in order to allow Treasury an opportunity to resolve the matter with the industry.

Respecting Treasury's wish at that time I deferred. It has been about a year now since our agreement. In light of the fact that the drill dates expire in a few months, the end of this year, and that we are now getting ready to go through another period of budget reconciliation coming up, when can we expect the administration to clarify this term for the industry?

Mr. WOOTTON. Mr. Chairman, on the subject of tar sands I am tempted to ask whether you would like the long story or the short story.

Senator BOREN. Just a——

Mr. WOOTTON. I will try to keep it to the true story.

Senator BOREN. Just a straight answer of clarifying and hopefully accepting the language that I intended to insert last year. [Laughter.]

I will insert it again this year if we have not reached a resolution in the next few weeks when this comes up again.

Mr. WOOTTON. The issue as you very well know concerns whether tar sands should be defined for tax purposes by reference to its physical characteristics or the process used to take it out of the ground. Taxpayers have favored the former approach and the Internal Revenue Service favors the latter.

In an effort to develop alternative approaches that could be used to break the deadlock, the Internal Revenue Service in March issued a request for public comments on the definition. Some were received and the IRS has reviewed them and continues to review them. I must say, though, that to the best of my knowledge none of those comments has yet provided a concrete basis for resolving the issue. The IRS continues to look at the various substance-based definitions that might be suggested. But I understand the matter has now gone into litigation with at least one of the taxpayers involved. And the IRS, while interested to hear other arguments, does believe that the process-based definition is the appropriate one.

Senator BOREN. Well, is this the final resolution then of this issue in your mind or is there still an effort being made using Department of Energy definitions to try to resolve it before we begin the mark-up?

Mr. WOOTTON. I have watched this issue develop over the past several months. I have begun to despair of an ability to develop a substance-based definition which would be acceptable to all concerned.

Senator BOREN. I am really disappointed to hear that. Because as I say, we were about to clarify it by law. I think the committee was clearly ready to act last year. We did defer to give Treasury time. This is not meant to be harsh, but I have to say that the clock is running and if you want one last chance to try to resolve it yourselves before we legislate appropriately on this matter, there is now a matter of weeks left in order to get that done. Otherwise we are going to press ahead and resolve it in a matter that makes sense in terms of encouraging the highest level of domestic energy production, which is what we are talking about here today.

Mr. WOOTTON. Partly in response to the IRS request another submission was made within the last month or so. I know that is receiving very serious consideration.

Senator BOREN. I would urge you to try to crack the whip if you possibly can and get this resolved for us. But otherwise, we do feel an obligation. We are talking about this serious dependency problem. I gather you would agree with me that when we are at 52 percent levels, an increase up to 25 percent of all the petroleum products coming into this country now coming from Middle East production that it is a serious problem from the point of view of national security.

Thank you very much, Mr. Wootton. We appreciate you being with us. Is this your first appearance before the committee; is that correct?

Mr. WOOTTON. The first that is open to the public. [Laughter.]

Senator BOREN. We are glad to have had you and we look forward to having many more opportunities to work with you.

Mr. WOOTTON. Thank you, Mr. Chairman.

Senator BOREN. On those occasions I hope more of my colleagues will be able to be here and participate in these discussions with you.

Thank you very much.

I might ask my colleagues, I see Senator Akaka has come. If I might ask him to come down to the witness table and also Congressman Andrews is here as well. If both of you might come forward down to the witness table. We are very pleased to have both of you with us this morning. Let me ask if the two of you might consult with each other. Are either one of you under a tight time constraint?

Congressman ANDREWS. I would certainly defer to the Senator. I would be happy to do so.

Senator BOREN. I thank my colleague from our Sister State to the south. We are privileged to have with us this morning the newest member of the U.S. Senate, our colleague from the State of Hawaii. I have just been privileged to work with him on another issue recently, the agriculture bill, also extremely important to both of us. I saw him take very effective leadership on behalf of an important amendment to his State in continuation of the sugar program. He successfully made the motion to preserve that program on the Senate floor.

Senator, I commend you for the effectiveness that you have already demonstrated as a Member of the Senate. We also welcome you to the Senate especially because of your knowledge of energy, alternative energy sources as well as traditional energy sources and your commitment to domestic energy security for this country. You certainly have a distinguished record from the House that you bring with you. It is a privilege for all of us to have you serving now with us in the Senate.

We are very happy to have your testimony this morning and I am happy to recognize you.

STATEMENT OF HON. DANIEL K. AKAKA, A U.S. SENATOR FROM HAWAII

Senator AKAKA. Thank you very much, Mr. Chairman. Thank you for your kind remarks. I thank you for your support on the agricultural program which is not finally passed yet, but we are hopeful will be done today.

Senator BOREN. It is a matter of national security as well.

Senator AKAKA. Yes, another kind of security.

Mr. Chairman, I thank you for allowing me to address the energy security concerns of the State of Hawaii. I have come to warn about Hawaii's vulnerability in the event of an oil supply disruption and to make a case for citing a regional petroleum reserve in the State of Hawaii.

In my prepared remarks I outlined the grave impact that an oil import fee or tax would have on the State of Hawaii. For example, a $5 per barrel import tax would cost every man, woman and child in Hawaii $106. This hearing, Mr. Chairman, will also examine the steps that can be taken to increase domestic energy reserves.

I have some very strong views on this subject which I would like to share with you and the committee. In the midst of the last energy crisis Congress established the strategic petroleum reserve. The purpose of the reserve was to minimize the impact of any interruption or reduction in oil imports. The Federal Government's conscientious efforts over the past decade to fill the reserve demonstrate that we are serious about our pledge to achieve greater security. However, the sad reality is that not all areas of the United States will be covered by this blanket of energy security. Unlike the mainland where the strategic petroleum reserve is providing real protection, Hawaii's energy security has steadily declined, grown weaker and weaker.

This has occurred, Mr. Chairman, despite Hawaii's unequal commitment to renewable energy. Compared to the mainland Hawaii faces a much greater risk of an oil supply disruption because we have no overland access to domestic sources of crude. While other States have access to oil by pipeline, rail or highway, in Hawaii all our crude oil and refined products arrive by ocean tanker.

Our total reliance on tanker deliveries make Hawaii exceptionally vulnerable to a cutoff of all oil supplies should a crisis disrupt imports. It is then that oil imports are severed. The strategic petroleum reserve will protect the rest of the United States from severe economic harm. Hawaii would not be so fortunate. Our only access to the strategic petroleum reserve would be through tanker delivery through the Panama Canal.

A recent study, Mr. Chairman, commissioned by the State of Hawaii indicates that the minimum delivery time for strategic petroleum reserve oil to Hawaii would be 53 days. This exceeds the State's average inventory by 23 days. Under these circumstances Hawaii's oil supply would run dry.

Soon thereafter our economy would grind to a halt. The Department of Energy has failed to establish regional petroleum reserves for unusually vulnerable locations such as Hawaii. That is why, Mr. Chairman, I have introduced legislation to establish a regional reserve for Hawaii. These bills call for a reserve of 90 days consumption. Believe it or not the Department of Energy maintains that Hawaii's emergency petroleum supply needs are most effectively met through central petroleum reserve in the SPR Salt Dome Caverns in Texas and Louisiana. This notion is absurd.

These facilities are as far away from Hawaii as Istanbul is from New York City. I urge you to go forward with the legislation to address our dependence on foreign oil and identify ways of increasing our reserves. As you do so, I urge you to design an energy strategy which addresses the needs of Hawaii as well as the U.S. mainland. I hope you will remember that our islands are rich in many things—especially beauty—put poor in indigenous fossil fuels.

Unless something is done now about Hawaii's vulnerability when the next oil crisis hits Hawaii will wither on the vine.

Thank you very much, Mr. Chairman.

Senator BOREN. Thank you very much, Senator Akaka. I understand the situation and I think your graphic description of the fertility of the security of Hawaii from an energy point of view if there were serious supply interruptions, this should sensitize us all again to just how much we are threatening the security of our country by not developing adequate domestic production.

I think the specific points you make about having actions to assure an emergency supply in Hawaii are well taken and I hope that these are comments that will be heeded by our colleagues, by the Department of Energy as well. Certainly I think that the legislation that you have introduced is well taken and well advised.

Let me say also I appreciate your comments favoring additional actions to be taken to encourage oil production within the bounds of the United States. In making that statement you are carrying on a tradition. Your predecessor, of course, served on the Finance Committee.

I can remember several years ago when we had tax legislation before us and there was an effort made to remove virtually all of the incentives for domestic production. That on several key matters they were decided by a one vote margin in this committee. I think that many assume that because Hawaii does not have oil and gas production that the Senator from Hawaii would not necessarily be sympathetic to the need of maintaining those incentives. Quite the contrary. He cast the deciding vote in favor of maintaining many of these incentives and he consistently worked for incentives for domestic oil and gas production as well as for alternative sources of energy and research, ocean tides, and many other forms of energy.

So I compliment you on carrying on his tradition of strong concern in the area of energy security.

Senator AKAKA. You are very welcome, Mr. Chairman.

Senator BOREN. Thank you for being with us.

I hate to say this, but we are just now having another vote on the floor. Senator Domenici, do you want to go over and vote and then come back?

Senator DOMENICI. Can I do it right now?

Senator BOREN. Do you want to go ahead and make your statement now? That will be fine. Do you want to join the witnesses there? Speak from either place.

Senator DOMENICI. May I sit right here?

Senator BOREN. That is fine. We welcome you. You have indeed been one of the most effective members of the Senate in terms of developing legislation that the most cost effective means possible would decrease the domestic production in this country and especially preserve much of our marginal production and encouraged enhanced recovery so that we do not waste the reserves in these old wells.

It has been a privilege to have joined with you as a partner on many of the proposals that you have made.

STATEMENT OF HON. PETE V. DOMENICI, A U.S. SENATOR FROM NEW MEXICO

Senator DOMENICI. Thank you very much. Mr. Chairman, let me just say that I think it is very interesting that you are holding this hearing on a day when newspapers across the country have a story that seems to indicate that the cartel may have fallen back in love. Maybe they are back together. It looks like they are getting along so well, they are going to raise the price of oil $2 a barrel.

Now obviously for some of us raising the price of oil means maybe we will start producing a bit more domestically. But, Mr. Chairman, the fact that we have grown so dependent upon foreign oil, and that the world is still significantly dependent upon the cartel's oil is ominous.

We are having an economic summit conference. The whole purpose of it is to get America's fiscal house in order so we can start growing again on a sustained basis with reasonably priced capital. If oil prices were to rise gradually and in a sustained manner under the guidance of a cartel, then all of the United States' growth potential could just quietly be sapped right out from under us resulting in dramatically increased energy costs. And we sit around doing absolutely nothing to minimize our dependence. I think this is a fair statement.

We do nothing to increase domestic production. As a matter of fact, it is tumbling every month; rig counts are down every month; production is plummeting, except for little spurts here and there in the natural gas industry, created by some exceptional treatment in the Tax Code to coal seam gas.

So it seems to me we really will not act until indeed there is a crisis. And what worries me is there might not be a crisis. There might just be a gradual sapping of America's economic growth by those who are content to see the price of oil set by the cartel at ever higher prices. This is especially frightening for a free world that is overly dependent and a United States that seems to have an insatiable appetite for consuming and no appetite for doing anything about it.

I would like to talk about a few things quickly. First, I suggest to you, Mr. Chairman, that even though some do not think the economic summit is going to work, I think there is an outside chance that it will. Mr. Chairman, there is a chance that the economic summit will work. I suggest to you, that we are probably going to ask for all of the revenues on the increased side and all of the revenue losers.

I urge that you seek with all of your capacity to put a couple of these significant incentives for oil and gas production in that loser column so that when we take the final package we will have an opportunity adopt some incentives. I am fearful if it is not in there, and if they are not in there, they are gone; and we will wait around for another tax bill. It would seem to me that that would be a long time coming.

Senator BOREN. I agree with you. If we miss this opportunity in the Budget Summit to include something positive for energy production, we may not have another opportunity for another decade.

Senator DOMENICI. That is right.

Senator BOREN. It is going to be far too late by that time to take care of the situation.

Senator DOMENICI. I am just urging, as I am sure you are, that we push pretty hard on it.

Senator BOREN. I will join you in the effort. I know Chairman Bentsen and I have discussed it and I know he will as well.

Senator DOMENICI. I am just going to talk about the situation we are in. I will just read a statement and then that should lead into my bill which I hope you have supported. I am not going to go into it very much. It is the Enhanced Oil Recovery Tax Act.

"The United States has produced more oil than any other nation in history. But unless new technologies are rapidly developed and installed the United States will leave behind twice as much in known reserves in its reservoirs as it has ever produced from them. Of this massive 340 billion barrel resource as much as 76 billion barrels could be made economically producible using technologies that could be developed, some of which are already in existence.

The economic recovery of this oil presupposes the use of existing wells. But the accelerating rate of well plugging could eliminate economic access to as much as two-thirds of the remaining oil by 1995."

Now if ever an asset, a resource, cried out to get tapped it is his 340 billion barrels of recoverable domestic oil. And if we don't act now, we will be in a serious dilemma because we will not be able to get it 6 years from now. So I urge that we proceed with this batch of incentives make the research and development tax credit absolutely available for enhanced oil recovery, that we go with the 27½-percent depletion allowance that we have recommended, and use the energy reinvestment allowance notion which I gather is rather acceptable to many of the people you have been talking to. The energy reinvestment allowance ensures that producers will reinvest the tax credit into further research and development.

If you can do that and a couple of other things, there is a real chance of capturing our own untapped resource at a very, very reasonable per barrel incentive rate. As you have so eloquently stated, "the most cost effective incentive around."

Senator BOREN. What is the cost under your proposal? What do you figure the cost at the margin per barrel of oil saved and made available through enhanced recovery would be?

Senator DOMENICI. Well let's see——

Senator BOREN. As I recall it is an extremely low figure.

Senator DOMENICI. It is extremely low, just 35 cents. [Laughter.]

Senator BOREN. Thirty-five cents a barrel? Is that correct?

Senator DOMENICI. That is right.

Senator BOREN. I remembered that it was very low and I thought it was under 50 cents; but 35 cents per barrel would be the effective cost of this tax credit to get additional reserves brought on line in usable form.

Senator DOMENICI. Right, and thank you for the opportunity to speak today on this matter of extreme importance.

Senator BOREN. I cannot imagine a greater bargain, either economically or from a national security point of view for the United States.

Senator DOMENICI. Also, when you talk with the chairman about working with this number for the Summit you can put a very good package together in this area, somewhere between $125 to $150 million.

Senator BOREN. Yes.

Senator DOMENICI. It is not a gigantic incentive when you are talking about it.

Senator BOREN. Exactly. I think it is important we not miss this opportunity.

[The prepared statement of Senator Domenici appears in the appendix.]

Senator BOREN. I apologize to my colleague from Texas. I will be back here hopefully in about 4 minutes and we will commence at that time.

Congressman ANDREWS. Thank you.

Senator DOMENICI. Thank you very much, Mr. Chairman.

[Whereupon, the hearing recessed at 11:38 a.m. and resumed at 11:52 a.m.]

Senator BOREN. We will resume. I am sorry that Congressman Andrews has now been caught up in what we were caught up over here, with votes. I am going to insert Congressman Andrew's full statement into the record. We hope that he will be able to get back, but now he is caught in a series of votes. I think they are conspiring against us today with what is going on on the floor.

Congressman Andrews has introduced bills on the House side which are companion pieces of legislation to the energy incentives for domestic production which I have introduced on the Senate side. They are virtually identical. He has really been an important working partner to me and to the members of this committee in the work that he has done on the House side. He has been a real leader on the House side in this whole effort.

I apologize to him in his absence that he got called away before we were able to get back and hear his testimony. But we hope he will be able to join us later.

[The prepared statement of Congressman Andrews appears in the appendix.]

Senator BOREN. We will turn now to Mr. Vito Stagliano, Associate Deputy Undersecretary for Policy Analysis at the Department of Energy. Mr. Secretary, we are happy to have you with us today and would welcome your remarks. Let me say in light of what has been happening to us, I would suggest perhaps if you could summarize your statement and we will put the full statement into the record and hit the high points for us. It would probably be the safest procedure so we can be sure we can hear what you have to say and the other panelists that will follow you with a minimum amount of interruption from the floor.

We are very happy to have you with us.

STATEMENT OF VITO A. STAGLIANO, ASSOCIATE DEPUTY UNDERSECRETARY OF THE ASSISTANT SECRETARY FOR TAX POLICY, U.S. DEPARTMENT OF ENERGY

Mr. STAGLIANO. Thank you, Mr. Chairman. Yes, I was intending to summarize my statement. I appreciate the opportunity to represent the Department of Energy today at this hearing. I will not dwell on the statistics of conditions in the market which you have eloquently addressed, but rather on the issue at hand—U.S. dependence on imported oil and the President's tax incentive proposal.

Mr. Chairman, there are two fundamental concerns that we have. The first is that we need to worry about the well being of all sectors of our economy, including the oil sector, whose productivity and performance, of course, affect the economy at local, State and Federal levels. The second is our increasing dependence on imports from regions that have had recurring instability associated with them.

The United States has addressed part of its concern on energy security by spending $20 billion in order to build what is now the world's largest strategic petroleum reserve. We will have to spend another $5 billion over the next 6 years in order to increase the reserve up to the administration's target of 750 million barrels which is the administration target.

The SPR, however, is not an import substitution program. It is an insurance policy. The day-to-day productivity and competitiveness of the domestic oil industry is not affected by the SPR in any substantive way. Our economic concerns are ongoing. The oil industry confronts, we think, a level of risk that is beyond its ability to contain. Few other industries, for example, would have to face a 60-percent drop in the value of their product over a 3-month period of time, as happened in 1985 and 1986, and few other industries would make investments that do not provide a return 86 percent of the time, as happened in investments in new field wildcat wells in 1986 to 1988.

Also, the U.S. oil industry is unique in the world. It consists of major integrated companies that remain competitive when confronted with a labyrinth of fiscal and regulatory regimes in the United States and other parts of the world. It also consists of thousands of independent entrepreneurs who operate on the margins and are responsible for the bulk of new wells drilled in the United States.

We cannot really expect any new fields to be brought into production in the United States, except along areas that are well known—in Alaska and on the Outer Continental Shelf. For a variety of reasons the Nation has decided to temporarily forego development of these resources. What remains, in terms of cost effectively produced domestic oil supply, is fairly limited.

In his budget the President for fiscal year 1990 and fiscal year 1991, as Mr. Wootton discussed, proposed five tax incentives aimed mainly at reversing the dramatic slide in drilling activity and at extending the productive life of marginal wells. In a report released this week the General Accounting Office asserts that these additional petroleum tax incentives are of questionable merit. The GAO maintains essentially that the incentives proposed by the administration are not cost effective because of Federal revenue losses in the range of $3 to $14 per barrel of additional production. It also maintains that filling the SPR would be a far more cost effective means of improving energy security. It maintains that the Federal tax system already favors petroleum production investments over those of other industries. And GAO maintains that U.S. producers are making investments abroad because of factors other than taxes.

The Department of Energy disagrees on every one of these counts. By our estimates the Treasury costs of the President's proposal vary from a low of 12 cents per barrel for the EOR credit to $9 to $12 per barrel for the exploratory IDC's credit. We calculate that the cost of the program would average about $3 per barrel.

Even if we agreed, and we do not agree, with the erroneous assumption that investment in the SPR is a clear alternative to investment in domestic production, the cost effectiveness of the former is not, as the GAO claims, greater than the cost effectiveness of the credits. The per barrel cost of the SPR oil currently in storage is $27 per barrel. But if Treasury borrowing costs are added and storage facility costs are added, the total Federal financial cost per barrel reaches $56, not $27.

On the tax rate issue, according to a 1988 EIA report on profiles of major energy producers, the average effective corporate rates on the worldwide operations of U.S. energy companies continuously exceeded those for Standard and Poor's 400 every year since 1974, except in 1988 when the rates were equal.

The GAO based its analyses of tax rates on marginal rates. But we believe that a comparison of average tax rates as we have done, is at least as instructive as GAO's modeling of marginal tax rates comparisons.

On the issue of overseas investments by U.S. energy companies, DOE believes that while geology and finding costs play an important part, the tax system is probably also a factor. When oil prices decline the U.S. system, which includes State, Federal and private takes—and the State and private takes were not accounted for by the GAO—compounds the burden on U.S. oil companies by taking an increased share of income.

In the United States, State severance taxes and private royalties which are beyond Federal control, can constitute a greater share of cash flow than income taxes. They are based on gross revenue—they are not based on income. Only in the United States do companies pay both a royalty to a land owner and a severance tax to State governments. The latter average 5½ percent on a production weighted basis. No State varies its severance tax to reflect the profitability of producers.

If you want to take another country as a contrast—Canada, for example—the tax system there is made more flexible by the use of royalty holidays and rates that encourage new exploration and development. The Federal Canadian Government receives no royalty payments. Provinces base their royalty rates on production levels, on current prices, and on well vintage.

In conclusion, Mr. Chairman, the Department believes that the tax incentive package presented by the President is cost effective. We believe further that GAO gave advice 2 years ago, in a report that they released on August 31, 1988 that is far wiser than the advice they provided in the report they released this year.

I would like to quote a part of the 1988 GAO report. It says, "In essence, the dilemma facing the United States . . . is that although current trends point to an emerging energy problem, . . . significant uncertainly exists in the forecasts, the costs of corrective action—in tradeoffs and dollars—are is considerable. Many options are available to the United States reduce its vulnerability," said the GAO in 1988, "such as providing tax advantages to industry and reducing or eliminating unnecessary regulation."

Mr. Chairman, GAO's advice of 1988 was heeded and Congress decontrolled natural gas prices. And in 1990 the President has proposed tax incentives that were recommended by GAO in 1988, and we encourage congressional action.

Thank you, sir.

Senator BOREN. Thank you very much, Mr. Secretary.

The first question that I had written down that I planned to ask you was your bottom line assessment of the recent GAO study. I think I do not need to ask that question. I think you have eloquently described the inconsistencies.

I have to say that I have looked at a lot of GAO reports over the years—and I do not mean this unkindly—but this is one of the least competent, least credible documents I have ever seen come from the General Accounting Office in all my time of looking at their studies. It is absolutely so ridiculous that I do not see how anybody reading it could take it seriously and I cannot imagine how these people ever put it together.

It does not even account for local tax burdens and private royalty owner takes in terms of looking at the total tax burden and the average tax burden. Looking at what it does to the revenue picture of the industry is unbelievable. It did not take into account the cost and impact on trade imbalances. It did not take into account the affect on related industries, supply and service, the infrastructure. We could just go on and on. And you very eloquently described many of the inconsistencies in the report.

I appreciate your testimony and I cannot imagine that anyone is going to take this GAO report with any level of seriousness, especially in light of what has taken in place, and especially in light of what we have looked at earlier in terms of our increasing dependence on certain sectors in the world, geographical areas of the world, which are perhaps the least reliable suppliers.

Let me just ask then one brief question on the subject that I already asked Mr. Wootton on. The Section 29 situation, has DOE give its advice to the Treasury on this matter?

Mr. STAGLIANO. Yes, sir; repeatedly. We have encouraged Treasury to act on this definitional matter. We have also suggested to them that unless this matter is decided by the end of September, it would be essentially useless to go on with it. But it is an IRS case and it is clearly in the IRS's hands. So we are not quite sure what other action we might take to press this along.

But I can assure you, we have tried to press it to the extent that we can.

Senator BOREN. I appreciate that. I hope the Secretary of the Treasury at his level, and the administration, perhaps even at the Presidential level, will address this matter. Because there is clearly sound advice coming from the Department of Energy and we need the resolution of it.

But I think you are right, it will become moot because we intend to resolve it for Treasury if they do not get it resolved themselves.

Thank you very much for your testimony. It is very helpful to us and we will put your full testimony into the record. I especially appreciate your analysis of the GAO study.

Mr. STAGLIANO. Thank you, sir.

Senator BOREN. Thank you very much.

[The prepared statement of Mr. Stagliano appears in the appendix.]

Senator BOREN. We will next call on a panel consisting of Mr. Charles J. Mankin, or Dr. Charles J. Mankin, I should more accurately say, professor of geology, University of Oklahoma, director of the Oklahoma Geological Survey; and Mr. Charles DiBona, president of the American Petroleum Institute.

Gentlemen, we are very happy to have both of you here. I know Mr. DiBona will forgive me if I give precedence to the witness from that State which has made the greatest contribution of all States to sound energy policy thinking, production, innovation, scholarship. Dr. Mankin, from the University of Oklahoma, has been advising me for many years, going back to my time as Governor on energy policy. He has always given me sound advice, especially a sound base of objective information, upon which we could make policy decisions.

Dr. Mankin, we would welcome your comments.

I might ask both of you again, in light of the hour and in order that we get all of our panelists in, if you could possibly hold your remarks to 5 minutes and summarize them. I will call on both of you before I interrupt either of you with questions.

STATEMENT OF CHARLES J. MANKIN, PH.D., PROFESSOR OF GEOLOGY, UNIVERSITY OF OKLAHOMA AND DIRECTOR, OKLAHOMA GEOLOGICAL SURVEY, NORMAN, OK

Dr. MANKIN. Thank you, Mr. Chairman. I recognize that most of the success Oklahoma has had in sound economic policy took place during your term as Governor.

Senator BOREN. I hope that that was written into the records accurately here. [Laughter.]

Dr. MANKIN. Mr. Chairman, the United States——

Senator BOREN. Take longer than 5 minutes, Dr. Mankin. [Laughter.]

I mean, you know, the Chairmen have to be reasonable around here and fair to all witnesses.

Dr. MANKIN. I will try to keep my remarks to within 5 minutes, sir.

The United States has only one really important reason to need crude oil. There are a lot of other uses for crude oil, but that one reason is for transportation. Alternative fuels and alternative systems, such as electric cars, ethanol, methanol make interesting academic discussions but the reality is that except for compressed natural gas for service vehicles and other vehicles that can be filled up from common sources of supply, crude oil will be required to meet the transportation needs of this country well into the 21st century.

Today as you pointed out in your opening remarks more than half of that transportation fuel supply is coming from foreign sources. With all of those attendant problems, as you pointed out forcibly in your introductory remarks, when one Middle Eastern country can rattle its saber at another Middle Eastern country and the price of our crude oil and refined products goes up, then you know that you are no longer in control of your own destiny.

We have two choices. We can rely on foreign sources of supply for crude oil and refined petroleum products or we can maintain a domestic industry that is capable of meeting all of our essential transportation fuel needs—and I underscore the term "essential transportation fuel needs."

To do so three things must happen. One is that the industry needs to be provided access to the most prospective unexplored acreages in the United States, namely the off-shore and on-shore public lands. Banning drilling in the OCS, banning drilling in wetlands because of something called "no net loss"—whatever that means—and other restrictions on public land will prevent us from realizing the full potential of the resource base of this Nation.

The second is to provide an economic value or floor price to crude oil. If we do not provide some stability in the price of crude oil you can see the kind of effects that it is having, not only on our ability to sustain a domestic industry, but also to the shock waves that are sent through the economy of this country.

The States regulated the price of crude oil by the process of controlling production as a result of estimated demand for more than 40 years. And in that period of time the production increased in this country, the public were provided with a secure and more than adequate supply of relatively inexpensive transportation fuel.

The third issue is that we must increase significantly the Federal budget for a focused program of oil and gas recovery research. Progress has been made in that area by the Department of Energy, but the amount of support in that direction is pathetically small. The States have already undergone processes of establishing tax credits and are also supporting a great deal of the needed research in cooperation with the industries within our respective States. But this is a national problem and the Federal Government needs to share and share importantly in that process.

To do nothing will ensure the demise of the domestic petroleum industry by the end of this century. Let me conclude my remarks by illustrating that statement with a few statistics from our State, Oklahoma. In 1989, Oklahoma produced 118 million barrels of crude oil and refined natural gas liquids. That was a 45 million barrel a year drop since 1985. If one projects that forward and continues business——

Senator BOREN. Say that again. It was how much this year?

Dr. MANKIN. The production in 1989 was 118 million barrels.
Senator BOREN. One hundred and eighteen?
Dr. MANKIN. One hundred and eighteen—1-1-8.
Senator BOREN. Forty-five million less than——
Dr. MANKIN. Than 1985.

If that trend continues, by 1991 the State of Oklahoma will produce less than 100 million barrels of crude oil. The last time Oklahoma produced that small a quantity was in 1919.

By 1995, if that trend continues, the State of Oklahoma will become a net importer of petroleum products. That is the situation for the fifth largest petroleum producing State——

Senator BOREN. It might put me in a larger voting block here in Congress at least, unfortunately.

Dr. MANKIN. For the fifth largest petroleum producing State in the Nation.

Mr. Chairman, it seems to me that this Nation is about to go out of the oil business. The Department of Energy has projected at the rate of abandonments that between 60 and 70 percent of our present proved reserves will remain unproduced by the end of this decade.

Sir, I believe the hour is approaching the bewitching hour of midnight. And unless we do something now we are going to see the consequences of inaction visited upon us in ways that will make the 1973 Arab oil embargo look like a Sunday School picnic.

Thank you, sir.

Senator BOREN. Well I do not know whether to thank you or not after hearing those alarming figures. But that is an incredible statement. I cannot think of a better way to encapsulate it. To think that our State, which as you say is the fifth largest producer, will become in a very short number of years an importer, a net importer of energy if we do not do something to change the situation. It is absolutely incredible.

The tragedy of that also being that roughly two-thirds of all the oil we have discovered in our State is still in the ground because we have not had the proper incentives for enhanced recovery to go back in and get it out. That is an incredible and an alarming statement.

What is happening in terms of the number of young people that are now training themselves to go into the energy field, as you have seen it. Putting on your University hat for a minute in terms of the numbers of students that are going into undergraduate and graduate programs in petroleum-related fields?

Dr. MANKIN. Since 1985 when the enrollment in geology was in the neighborhood of 500 majors the number of undergraduate majors that are expected to enroll in the School of Geology at the University of Oklahoma this fall has declined to something in the order of 19. We have 13 new graduate students that will be entering the program this fall, one of whom is a U.S. citizen.

Senator BOREN. Only one is a U.S. citizen?

Dr. MANKIN. That is correct. Petroleum engineering has an identical situation except their numbers are perhaps in some respects somewhat smaller.

Senator BOREN. So we are going down from 500 down to 19. And in our graduate program only one American citizen entering the graduate program at the University of Oklahoma in these fields.

You know, again, I cannot think of any more dramatic way to indicate exactly what we are doing to domestic energy production. If we want to put this country in the hands of the Saddam Hussein of this world, we are well on the way to having a lack of an energy policy that is going to cause that.

Dr. MANKIN. Yes, sir.

Senator BOREN. Thank you very much.

[The prepared statement of Dr. Mankin appears in the appendix.]

Senator BOREN. Mr. DiBona?

STATEMENT OF CHARLES J. DI BONA, PRESIDENT, AMERICAN PETROLEUM INSTITUTE, WASHINGTON, DC

Mr. DIBONA. Thank you, Mr. Chairman. I appreciate the opportunity to testify. I would like to cover three basic points. First, the Nation's ability to provide its oil from domestic sources is deteriorating rapidly. Second, conservation can make an important contribution; but conservation alone cannot resolve them. And third, public policies to enhance energy supplies can be implemented that will considerably improve both the Nation's economic performance and its energy security.

When I testified before this committee in January, 1987 I warned that U.S. oil import dependence was increasing rapidly. I stated that, "Some projections indicate that the United States could be importing almost one-half of its oil requirements as early as 1990."

In fact the import share, as you have already pointed out, was almost exactly 50 percent for the first half of this year—the highest percentage ever for a 6-month period. This compares with an import share of only 31 percent as you have shown up there on that chart for 1985.

The fall in oil prices both stimulated U.S. consumption and discouraged petroleum production. Growth in oil consumption accounted for most of the rise in imports between 1985 and 1988. However, consumption stabilized in 1989 and has declined this year. While the downward trend in domestic production has accelerated, domestic crude oil production now is declining at an annual rate of about 500,000 barrels per day.

Drilling activity which is an advance indicator of production offers little basis for optimism. So far this year the number of active drilling rigs and oil well completions are up from last year's severely depressed levels but are running at less than one-third of the peak levels of the early 1980's. I might add that never in the 50-year history of the record of these drilling rig counts has there been for so long such a low level. This is an unprecedented period since 1985.

Incidentally the average for this 52 year period was 1,800 rigs. So not only was the period that you showed for prior to 1985, it was actually the 52 year history. It is an amazing drop.

Further, both private and government agencies, including the U.S. Department of Energy, expect lower domestic oil production, greater U.S. oil consumption and larger imports over the longer run. Thus, under current policies the United States may import on the order of two-thirds of its oil by 2000. The exact import share depending heavily on future oil prices and U.S. energy policies.

To address this growing problem the Federal Government should both encourage economically efficient energy conservation and remove undesirable constraints on domestic energy production. Even if extremely aggressive conservation policies are adopted, however, sustained and economic growth will require additional energy supply.

On the supply side several measures would stimulate domestic production substantially. They include increased leasing of Federal land, certainly not the severely restricted off-shore leasing policy recently advocated by the administration; the avoidance of environmental and other regulatory requirements whose benefits are not commensurate with costs; and tax incentives for exploration and production like those contained in S. 449, the proposed Energy Security Act of 1989 which was introduced by you, Mr. Chairman. These measures would have important economic, as well as security, benefits.

Finally, the Government should not use new or increased energy taxes to resolve the Federal deficit problem, since such taxes would not increase domestic energy supplies but would impose very large costs on the economy. Several studies have found that energy tax increases would cause higher inflation, more unemployment, lower real incomes and the loss of international competitiveness for American industry generally.

In addition, because of these damaging economic effects the Federal revenues raised by energy taxes would in large part be offset by revenue losses from other sources and by higher Government expenditures for income maintenance programs.

For all these reasons, I urge you to focus on policies to augment conventional domestic energy supplies as an important part of the sound of national energy policy.

Thank you.

[The prepared statement of Mr. DiBona appears in the appendix.]

Senator BOREN. Thank you very much.

Let me ask both of you, we have had this project here of falling domestic production. I know we have gone down 6 percent in domestic production in the first half of this year. We are still at very high levels of energy usage. So the gap between our domestic production and our usage is growing higher, greater every single day. What is the main reason, do you think in terms of this increasing gap? What is the main factor, if you were to isolate one or two factors, that you think are really at the heart of the decline in domestic production, the increase in this gap between our domestic supply and demand? What would you list?

Mr. DIBONA. Well, of course, after 1981, the drop in price certainly had a very major impact on the ability to go out and find and develop oil and gas. So that probably was the biggest single factor. Right now, although there has been some price recovery, that continues to be a problem. But a problem of growing magnitude, even if the prices do increase, will be the inability to go and explore oil in areas where it is likely to be found, which is on Government lands.

The decision to prevent oil exploration in most parts of the offshore is a very, very serious one. And the inability to open up the Anwar area. So even if we through a combination of tax relief or price increases bring about capability to increase production, it will have to be done on a limited area, mostly on-shore, lower 48.

Senator BOREN. Dr. Mankin?

Dr. MANKIN. I would certainly agree with that. Certainly the decline in price has had a dramatic effect on the ability of the industry to sustain an exploratory and development effort. At the same time that decrease in price has encouraged increased consumption. So those two patterns have caused that gap to widen.

I would like to just make one observation in support of the view that there seems to be a kind of conventional wisdom, particularly in this town, that there is no more oil left to be found.

Back during the early 1980's there was I guess a period of time that some of us described as the feeding frenzy of the industry when there was a great deal of increased activity, from 1977 through about 1985. There is a view that all they did was drain existing fields faster. The fact of the matter is that from the period of time from 1977 through 1985 during this period of exploratory and development activity 27 billion barrels of oil were discovered that were not accounted for by the approved reserves at year end, 1976; and are not accounted for by the decline in reserves at the end of 1977.

In addition 137 trillion cubic feet of natural gas were discovered during that same period of time. Now admittedly there was a lot of money wasted during that period of time in drilling by groups of people who came into the business because it attracted a lot of people who knew very little about—knew how to spend money, but did not know how to find oil.

But nevertheless there were a lot of responsible operators and they did find a great deal of oil and a great deal of natural gas; and, therefore, the view that this Nation is running out of oil, in fact, it is running out of opportunities to search for it by restrictions on public land. They are running out of incentives to make those kind of investments because of instability in prices and a very adverse tax situation.

Mr. DIBONA. I might just add to that, the statistics show that the amount of oil found per active exploratory rig have been constant since 1947. That is, we do as well today because we know a lot more about how to do it. And as a consequence, there has been no decline in the amount of oil found per active exploratory rig. That continues to be 10 million barrels of oil equivalent per rig.

Senator BOREN. So this share decline in the rig count of exploratory rigs is a real indicatory of our failure to add to the reserves and find new reserves for this country.

Mr. DIBONA. Yes. And it has implications for future production.

Senator BOREN. Let me ask, Mr. DiBona, is the repeal of the proven property transfer rule, in your opinion, still a necessary step for us to take?

Mr. DIBONA. I think that is a very useful, one of many useful things which you included in your bill. That that would be a useful and important thing to do.

Senator BOREN. Would you explain why that is?

Mr. DiBona. Well it permits the sale of property to an independent who might be able to operate it more efficiently than a larger company could and, therefore, continue an operation in oil that otherwise might not be produced.

Senator Boren. It might be economic for an independent because of tax consequences and other reasons, sometimes even just personal labor invested in a particular operation.

Mr. DiBona. Yes, because you prolong the life.

Senator Boren. We are talking about avoiding premature plugging and abandonment. This is related to that, the need to prolong the life.

Let me ask both of you just very briefly because we do need to move on to the next panel, your judgment—Mr. DiBona you made a quick reference to it, the impact on the economy that a Federal gasoline tax a BTU tax, or a carbon tax might have. We keep hearing some word out of the budget summit and here we are in the amidst of discussing our declining domestic production, the dangerous reliance upon imports and what that could eventually do to the cost of production of all products in this country. Should we be discussing these kinds of taxes primarily on the energy sector at the time that we have these terrible problems of increased dependency?

Mr. DiBona. We think it is unwise because we have, as a consequence of a very active energy sector in this country, developed a manufacturing sector in other areas, and a farm sector, that are very energy intensive. We have built in this country an infrastructure which has depended on ample, low cost energy supplies.

Now if you take a country with that mix of goods and agriculture, and impose upon it higher costs than would exist in other parts of the world. The ad valorem tax, which is very much discussed, for example, would impose a tax on U.S. manufacturers that does not exist in the countries with which we compete and would put us at a very strong competitive disadvantage.

When that is taken into account the effect of these taxes has much greater impacts upon the GNP by a factor of several times than the total tax collection.

Senator Boren. Dr. Mankin?

Dr. Mankin. I would certainly agree with that. I cannot see where—the only thing a gasoline tax might accomplish is if the money were put into reducing the Federal deficit. It will do absolutely nothing in support of finding or developing additional hydrocarbons in the United States. It might do a little something if it is high enough to encourage conservation. But it will also have, as Mr. DiBona has pointed out, a very adverse ripple affect throughout our economy because of the reliance we have on the use of transportation fuels to really maintain our economy.

By the same token, the hydrocarbon tax or carbon tax will probably have some adverse affects rippling through the economy because we use different forms of energy for different components of our economy. And if you put a disproportionate tax on one part of it over another you are going to have some rather significant dislocation affects on the economy.

Senator Boren. Well thank you both very much. The President has talked in the past about revenues that do not impede our competitiveness or economic growth in the country. I hope that that standard will be kept in mind when the budget summiteers continue with their work.

Thank you both very much for taking the time to be with us.

We will call our next panel before us now. It is a panel consisting of Mr. James Russell, president of Russell Petroleum Co., and president of the Texas Independent Producers and Royalty Owners Association (TIPRO); Mr. Conley Smith, chairman of the tax committee of the Independent Petroleum Association of America, who is from Denver, CO; Mr. James Payne, president and chief executive officer of Santa Fe Energy Resources, and president of the Domestic Petroleum Council; and Mr. Craig Goodman, tax and legislative counsel for the National Stripper Well Association, and former Director for Energy Tax Policy of the U.S. Department of Energy.

We are very pleased to have all of you with us today. Again, I would ask if you could summarize your comments as we still have another panel also that will follow you. I will try to restrain myself from asking questions, although it is difficult to do with the kind of alarming statistics that we have been hearing today, until all of you have finished your opening comments.

Why don't we just proceed right down the row. Mr. Goodman, we are happy to have you and we will begin with you.

Mr. GOODMAN. Thank you.

Senator BOREN. We will put your full statements into the record. Then if you can summarize the high points for us, that would be appreciated.

Mr. GOODMAN. Thank you. I will, Senator.

Senator BOREN. Thank you.

STATEMENT OF CRAIG G. GOODMAN, TAX AND LEGISLATIVE COUNSEL, NATIONAL STRIPPER WELL ASSOCIATION, AND FORMER DIRECTOR, ENERGY TAX POLICY, U.S. DEPARTMENT OF ENERGY, HOUSTON, TX

Mr. GOODMAN. Senator, I am very pleased to be here today on behalf of the National Stripper Well Association. Our organization represents the operators of more than 450,000 crude oil wells in the United States. That is 75 percent of all the crude oil wells that are currently operating in this country. We also represent 3.8 billion barrels of proven, recoverable domestic reserves.

Stripper wells are being permanently abandoned in the United States at a rate in excess of 17,000 wells per year. These wells and the domestic reserves behind these wells represents a significant national resource. In the United States today producers are actually being taxed on the capital they invest to drill new wells. For many of these producers the modern tax code virtually bars the return of this capital.

In addition to the obvious legal implications of this, taxes on invested capital force the premature abandonment of marginal wells and at the same time penalize efforts to replace the domestic production and reserves that are being lost. In essence, Senator Boren, the U.S. Tax Code is now encouraging the depletion of America's resource base. We are in effect draining America first.

At a time when clean air and tax fairness are high priorities, there are no valid policy reasons to penalize the capital that is invested to find and develop new domestic reserves.

Our written testimony identifies the provisions of the Code that impose these direct taxes on drilling capital. We have also attached to our testimony an extremely modest proposal, with an extensive analysis, that would reduce this capital tax consistent with both tax reform and our current budget deficit.

Imposing a tax on the capital invested to maintain or replace lost production increases both the costs and risks of new drilling and lowers the after-tax return from these investments, particularly as prices, revenue, or profitability decline. Today in the United States capital invested in new drilling by over 75 percent of the Nation's independent producers will cost them more and return to them less than the exact same investment would to virtually any other company who is subject to the regular Federal income tax code.

Not only are these tax penalties regressive and anticompetitive, but they violate the basic premise of tax reform itself, namely tax neutrality. Today the Tax Code and a producer's tax paying position, rather than the underlying economics of an oil or gas project, can actually determine whether or not a tax disadvantaged firm can replace their depleting reserves.

Tax Reform never anticipated this result because Tax Reform never anticipated a 60-percent decline in oil prices. And it was this combination of regressive penalties, together with the price collapse, that causes these results.

The essence of the problem is, that U.S. Tax Reform increased substantially the time within which capital invested in new drilling and reserve replacements can be recovered. The National Stripper Well Association strongly supports the industry's efforts and your efforts to enact plow-backs, credits and other means that you mentioned earlier as a way to reduce both the regressiveness and the anticompetitive impacts that I have described.

We also strongly support your Marginal Production Incentive Act and we believe that this Act can help stop the loss of U.S. reserves and production. However, we would like to stress that most importantly the National Stripper Well Association urges this Congress to reduce or eliminate the current tax penalties that exist on the capital that we invest to drill new wells.

The concept of treating drilling capital as income for alternative minimum tax purposes is a relic from the time of the OPEC oil embargoes and soaring oil prices. For over 75 percent of all the Nation's independent producers Internal Revenue Code Section 56(g) and 57(a) have become a direct tax on capital. Yet without these new wells, independent producers are merely liquidating our assets.

IDC expensing has been in the Code since the beginning of the century. However, contrary to the GAO report, current tax law artificially forces us to recover our IDC investments over 14 years over the life of a statistically average U.S. reservoir. Even considering the flaws in the revenue estimation process, this legislative proposal could inspire over 1300 new projects, $4 billion in new investments, 800 million barrels of new reserves; and all of this could

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happen before the Treasury would receive a discounted impact of $100 million. This represents 11.5 cents per barrel.

I might also add that each new project started because of this proposal would add over $13 million in new wealth to U.S. society and over $2.7 million in new taxes to the Treasury.

Senator Boren, we believe that the time to invest in America is now. Tax equity and efficiency require a new direction in U.S. energy tax policy and we urge your leadership on these important issues.

Thank you.

[The prepared statement of Mr. Goodman appears in the appendix.]

Senator BOREN. Thank you very much, Mr. Goodman. I think that this is the water torture this morning. I do not know what is going on. There is another vote on the floor.

But I think, Mr. Payne, hopefully we can receive your comments before I have to go and then I will come back and we will complete with the panel. Again, I apologize. They are not cooperating with us very well today.

Mr. PAYNE. That will guarantee I will make it in 5 minutes. [Laughter.]

Senator BOREN. Go ahead with your statement, sir.

STATEMENT OF JAMES L. PAYNE, PRESIDENT AND CHIEF EXECUTIVE OFFICER, SANTA FE ENERGY RESOURCES, INC., AND PRESIDENT, DOMESTIC PETROLEUM COUNCIL, HOUSTON, TX

Mr. PAYNE. Thank you very much for allowing us to testify here today. As you said, my name is Jim Payne. I am president of Santa Fe Energy Resources. But today I am here on behalf of the Domestic Petroleum Council of which I am serving as President this year.

The Domestic Petroleum Council represents the large independent oil and gas producers in the United States. Our membership accounts for about 35 percent of the oil and gas reserves that are held by independents in the United States

I am not going to spend a lot of time today talking about the role of increasing dependence upon accelerating imports. Further, I am not going to talk a lot about the accelerating decline that we have in our U.S. production base. I think that has already been adequately covered. I would like to spend my time talking about what we consider a reasonable solution to that.

The U.S. oil and gas business, especially the independents, have been in a legitimate and significant recession for the last 5 years. And yet at the same time we have been in a recession, our oil and gas production—which you can consider a critical natural resource, since it is certainly a high-risk venture, it is capital intensive and it takes a long lead time to get done—that production has been under a very heavy tax burden.

The alternative minimum tax that you have heard discussed several times was the biggest corporate burden—when prices were good we had the windfall profits tax; and then suddenly when prices got bad we discovered we had something called the AMT. Just as a matter of interest, Santa Fe Energy had a bad second quarter this year and I noticed that we paid the Federal Government $8 million and we had a loss.

Senator BOREN. You had a loss?

Mr. PAYNE. We had a loss, yes.

The effect of the alternative minimum tax really is a double taxation on drilling; and drilling, of course, has the direct result of adding new reserves in this country. While AMT is a disincentive to our business, our proposal today is in terms of a tax incentive. We feel that if anything is really going to be done about the problems this Nation faces it is going to take a tax incentive to get it done.

Our tax incentive is based really on three premises. Number one, it needs to be broad-based. Number two, it needs to stimulate those activities that are going to find new reserves. And number three, it needs to be efficient. And we think the proposal we are going to make today meets all of those. In fact, our proposal really is an extension and modification of work that you have done and other people in Congress have done before us.

Essentially our proposal is, number one, we have a 15-percent credit on exploratory activities; and we have a 5-percent credit on development activities. The reason exploration gets a higher percent I think is obvious. It takes exploration to generate new gas reserves and new oil reserves. You can get the others through development you know, shifting from proved to probables and probables to proved, that type of thing. But it takes exploratory drilling to find new reserves.

We recommend a 5-percent credit for development mainly because that credit will accelerate the production process and some development projects will be accomplished that would not otherwise. The items that we are recommending we take a look at or give a credit to are (1) G&G, which are the geology and geophysics, which gets your projects started, finds your prospects; (2) we are recommending that it be on IDC's, the costs involved in finding new oil when you drill; and (3) some of the tangible properties directly related to production, such as platforms and production equipment.

The other item we are recommending is that we go back and set an expenditure ceiling. Basically that ceiling would depend on the capital expenditures of the parties involved for the last 5 years, sort of an average. If you spend more than that average, in other words if it is new money that is coming into the system to find new oil and gas, then 100 percent of that new money is eligible for the credit. Up to that spending ceiling level only a partial amount is eligible for the credit. But we would argue that the credit be broad-based, independent of the kind of company classification. We would recommend that it be consistent, that it stays in place when prices go up and when prices go down so that we have a little more stability in our industry. And finally we would feel very strongly that the credit should go against both our regular tax and the alternative minimum tax.

So that is basically our proposal. I think it meets all the criteria we talked about. By definition it is broad-based. Anybody who wants to do it can do it. It stimulates drilling and prospect development which generates new oil. And finally, we think it is efficient because we are saying to the oil industry, the people that know how to look for oil and gas, you decide how to spend your money. We are not going to create any artificial support of something that isn't efficient by this approach.

So that is it. I think if this Nation is truly serious about solving its problems—and I could not agree more with what I have heard today as to what those problems are going to be and what the future portends—then I think this is a very legitimate way to take a look at it. We think the cost associated with it is reasonable; and we would recommend to you that you consider asking for an estimate of revenue from the Joint Committee on Taxation.

Thank you.

Senator BOREN. Thank you very much. We will do that and we will have those figures so that we can make sure that this proposal is given full and serious consideration in our deliberations as we look at the final budget package this year. I appreciate the very constructive proposal you have brought to us.

[The prepared statement of Mr. Payne appears in the appendix.]

Senator BOREN. I apologize. I will be back. I promise our next two witnesses that their testimony will be heard. We will have to stand in recess about 5 minutes while I go over and back to vote.

[Whereupon, the hearing recessed at 12:44 p.m. and resumed at 1:02 p.m.]

Senator BOREN. We will resume again. This is sort of like a banquet or a progressive dinner that moves around. But again, I apologize to you. It is just beyond our control.

Mr. Smith, we would be happy to have your testimony at this time.

STATEMENT OF CONLEY P. SMITH, CHAIRMAN, TAX COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA AND OWNER, CONLEY P. SMITH, OIL PRODUCER, DENVER, CO

Mr. SMITH. Thank you, Senator Boren. My name is Conley Smith. I am an independent oil and gas operator from Denver and I chair the Tax Committee of the Independent Petroleum Association of America.

Mr. Robert Gentile, Assistant Secretary for Fossil Energy at DOE, told the Interstate Oil Compact Commission in Bismarck last month that the United States is in danger of losing 70 percent of its currently available on-shore oil, at the current rate of well abandonments. That is in Graph 2 of our written statement which you have. And as to the rest of my comments concerning the state of our industry, I think you have covered it better than I could.

So it is certainly in order to inquire into what is happening in the oil and gas industry today. Let's take a look at who the players are in this depressed domestic drilling scene. In the earlier boom years independents accounted for over 90 percent of all drilling activity. In the past 4 years that independent share has dropped in the neighborhood of 65 to 70 percent. And in spite of the increased emphasis on foreign activity by the major oil companies, their share of domestic drilling activity has tripled.

What accounts for the drilling activity in the country today? Well Section 29, Tax Incentive Drilling, is very significant, especially for coal gas. The Petroleum Engineer, which is an industry publication, projects that one-third to one-half of all 1990 natural gas drilling will be Section 29. So, do not let anybody tell you that tax incentives do not get action; they do get action. We support the extension of the Section 29 credit and the reinstatement of tight sand natural gas as a qualifying fuel.

You are hearing a lot about horizontal drilling. It is receiving a great deal of attention. Conventional, vertical hole drilling by both majors and independents is far down at less than one-fourth of 5 years ago.

Who drills the wells today? The major oil companies and wholly-owned subsidiary companies of transmission companies, utilities, diversified companies are active. What do they have in common? They have combined financial statements which guarantee a virtual exemption from the alternative minimum tax.

Then, there is a new breed of independent, companies who have just severed their upstream expiration and producing segments and cast those companies out on their own to sink or swim, companies like Oryx and Meridian and Santa Fe Energy, who is represented here today, Anadarco and others. These companies are among the most active and successful of any in the country, and they will be active and perhaps successful until the accumulative affects of the alternative minimum tax catch up with them. Then they will be caught up in the squeeze just like the rest of us independents unless you change the law.

Then there are a few entrepreneurs and scalawags like me who have just gritted their teeth and tried to drill through the downturn. We have endured operating losses and are taking the alternative minimum tax hit, as the case may be. The problem with operating losses is that one tends to run out of money, as even the U.S. Government seems to have discovered.

You know, I calculate the economics for today's oil prospects at today's prices to be about the same as the 1983 to 1984 era. Gas prospects are not quite as good, but the drilling activity is less than one-fourth of the level of that era. Why is that? It is not purely petroleum economics. The culprit is the alternative minimum tax. Both percentage depletion and intangible drilling costs in excess of 65 percent of net oil and gas income are treated as tax preference items subject to alternative minimum tax.

The regular and alternative minimum tax rates are so close together that almost any level of activity triggers a nasty alternative minimum tax consequence. If a person is an oil and gas producer, percentage of depletion triggers him into the alternative minimum tax. If the person is not an oil and gas producer, he becomes subject to the alternative minimum tax for intangible drilling costs. No wonder we have run out of investors.

The oil and gas industry is still tax driven. Now it is also profit driven, but it is certainly tax driven as it has always been. No wonder that the oil and gas activity of the traditional independent is so low. I wondered if the Congress knew what they were doing when they passed alternative minimum tax in 1976 and then updated it in 1982 and again in 1986.

We independent oil and gas folks maintain there is an awful lot of oil and gas still to be found in this country. Previous witnesses have said that. We think there is a couple of ways to clear up our problem. The clearest way is to delete intangible drilling costs and percentage depletion which is a form of depreciation on a wasting mineral asset as tax preference items in the alternative minimum tax. The second way is a tax credit drilling and completion expenditures, which is deductible against alternative minimum tax or regular tax.

We hope that you will see fit to take one of these two actions. Instead, what we are hearing in the name of budget reconciliation are proposals for carbon taxes, BTU taxes, and Federal ad valorem taxes. With the domestic energy base in this country deteriorating across the board, this would be the worst possible time to inhibit energy production with any kind of a wellhead tax.

If the Congress is determined to enact an energy tax, clearly that tax must be as broad as possible and applied at the consumer level. Let me also add that energy used both onshore and offshore to produce minerals should not be subject to taxation.

Thank you very much, Senator.

Senator BOREN. Thank you, Mr. Smith. I understand your comments. When you asked did Congress know what they were doing when they passed the alternative minimum tax, there is a short answer to that and the answer is no. I would be happy to share with you some of my own comments back at that time on this committee on that particular proposal; and I think you will see that we agree completely. Unfortunately the things I said then the consequences would be are exactly the consequences which you are now reporting to us have taken place.

Mr. SMITH. Yes, sir; thank you.

[The prepared statement of Mr. Smith appears in the appendix.]

Senator BOREN. Mr. Russell?

STATEMENT OF JAMES E. RUSSELL, PRESIDENT, RUSSELL PETROLEUM CO., AND PRESIDENT, TEXAS INDEPENDENT PRODUCERS AND ROYALTY OWNERS ASSOCIATION, ABILENE, TX, ACCOMPANIED BY STACEY SMYRE, CHAIRMAN, NATIONAL ENERGY POLICY COMMITTEE, ALSO ACCOMPANIED BY JULIAN MARTIN, EXECUTIVE VICE PRESIDENT

Mr. RUSSELL. Thank you, Mr. Chairman. My name is James E. Russell and I am an independent oil operator from Abilene, TX; and have been there for some 40 years in this business. Today I represent the Texas Independent Producers and Royalty Owners Association as president. Also with me today is Stacey Smyre, who is chairman of our National Energy Policy Committee; and Mr. Julian Martin, who is our executive vice president, in the event you have any questions I cannot answer.

Currently petroleums overall portion of our energy consumption in this Nation amounts to about 25 million barrels per day, which is approximately two-thirds of the Nation's energy market. In my written statement I outline the contention that this can be a stable amount for several years. An effective national energy policy should pose the question: To best serve the Nation's economic, environmental, and security interest what portion of that 25 million barrels daily should be filled by domestic oil, domestic gas, and imported petroleum during the decade ahead?

Once that guideline is struck, subject of course to periodic revision, the next question arises. What changes in governmental programs and taxing patterns can be initiated to encourage the appropriate supply pattern from these three basic sources? Under current national policy supply contribution has shifted from domestic oil and gas to imports annually since 1985 by an average of some 800,000 barrels per day.

This shift has led to several undesirable consequences. It has added more than $20 billion to the Nation's annual petroleum import bill which now approximates $50 billion. It has increased tanker flow of oil into U.S. waters by more than 40 percent, thereby raising the risk of oil spills in U.S. coastal waters by a similar margin. The move to imports has dramatically progressed and increased U.S. reliance on the relatively insecure Mideast oil, since virtually all new import flow much come from the Persian Gulf.

Under other undesirable results include increase in governmental costs to expand and maintain the strategic petroleum reserve and protect the tanker sea lanes used to transport the larger import volumes. In addition, of course, there is the damage that occurs to the domestic oil producing industry and the Nation's economy, as the infrastructure and job opportunity in the industry is decreased or moved abroad by the shift to imports from domestic production.

Obviously it would be desirable policy to reverse this shift and begin to displace imports with domestic oil and gas production or at least end the shift to imports by establishing domestic supply stability. However, two questions must be dealt with before corrective action can be taken. First: Are there sufficient domestic oil and natural gas reserves available for the productive capacity needed to reverse or halt the shift? If so, are there feasible mechanisms and incentives available to the Nation that make it worthwhile to generate the industrial capability needed to reserve or halt the shift, particularly in view of the adverse circumstances now being experienced under current policy that allows the shift to occur?

TIPRO firmly believes the answer to both questions is yes. In the written testimony before you the Nation has sufficient oil and gas reserves that can be developed at prices approximately $25 per barrel for oil, and $3 per MCF for gas. In the process of stabilizing or even reversing the shift from domestic petroleum production to imports now under way under current national energy policy several political decisions must be made.

These political decisions must explore whether to stabilize energy prices at levels required to achieve desirable goals or to encourage through tax incentives producer behavior aimed at maximizing reserve recovery. In making these decisions Congress and the administration should continue to recognize the independent producer and his special role in domestic exploration and production.

While his ranks have diminished by a third since 1986 with more expected to leave at any time, the survivors should be stronger and are stronger and more effective today than ever before. With the right economic motivation they should be fully capable of maintaining their historic portions of exploration and production maintenance activity.

Among the remedies available, TIPRO maintains that an oil import fee system would be the most effective and by far the simplest and most direct device there is to encourage a change in the current shift from imports to domestic production. This one economic program would lead to dramatic improvement in domestic petroleum exploration and production, encourage effective conservation and energy use and as a useful political by-product provide public funds to help trend the Nation's budgetary deficit.

Another price stabilization proposal would attach a substantial environmental fee to all imported oil and to U.S. coastal waters. This approach would link the problem of import growth to the problem of environmental degradation caused by tanker spills and processing of foreign oil in the Nation's ports and waterways. TIPRO supports this approach as a viable option to this basic import proposal.

Should Congress however decide to turn to the Tax Code for domestic supply solutions TIPRO joins other witnesses in seeking foremost corrective action on treatment of IDC's and percentage depletion under the alternative minimum tax rule.

The Association specifically endorses the two changes presented by the National Stripper Well Association today.

In conclusion, TIPRO strongly believes that domestic petroleum producing industry and the Nation's petroleum reserve holdings are fully capable of maintaining current production levels well into the next century, thereby ending the shift of imports now being experienced. However, the success of this effort must rely on a new national energy policy that encourages maximization of domestic production, discourages import growth and stabilizes demand growth through a new emphasis on conservation and energy use.

Thank you very much for allowing me to appear.

Senator BOREN. Thank you very much.

[The prepared statement of Mr. Russell appears in the appendix.]

Senator BOREN. Let me thank all of you.

Mr. Goodman, I understand that you have done some research on the whole impact. You have talked about what is in effect really a tax on working capital. You have done some research on our energy tax system and as it compares with other industries in this country, but also as it compares with taxes on energy producers in other countries.

Mr. GOODMAN. Yes, sir.

Senator BOREN. Would you be willing to supply that research or highlights of that research for us for the record?

Mr. GOODMAN. I would be honored to, sir.

Senator BOREN. I would appreciate it if we could do that.

[The information appears in the appendix.]

Senator BOREN. Let me ask in terms of the Domestic Petroleum Council proposal, I think you indicated, Mr. Payne, that you thought that we could through tax incentives now get even the credit proposal that you have made, bring in new reserves at incremental costs that would be even lower than the historical full cost rates. Why is that?

Mr. PAYNE. The model that we have run, and we have tried to be fairly straight arrow with it, shows that we could add reserves at about $2.50 a barrel under this proposal. The basic reason for that is, it is an incremental type reserve. You have already got your fixed cost for people, overhead, your seismic base, that type of thing. It is an incremental add on so you are not having to add those other fixed costs that go into your full cost accounting.

So it is a very effective "bang for your buck" that you are going to get with this type of proposal.

Senator BOREN. Do you think that we would have any increases in the costs of production and exploration as a result of tax credits, in other words in the increasing levels of activity? Will that cause the costs of drilling and so on to go up?

Mr. PAYNE. Not under the proposal we have. It simply is not large enough. Obviously, you know, if you went back to the 1979-80 period you do cause disruptions in the service infrastructure. But I think in the proposal we are talking about the capacity is there. Again, it is almost an incremental savings from the service side.

Senator BOREN. Right. In other words, we have such an excess of capacity right now that——

Mr. PAYNE. That it can easily support this additional——

Senator BOREN. It can easily absorb it; and, in fact, in some ways maybe even decrease costs in some ways and that it would cut some losses of service industries that are already in their overhead costs.

Mr. PAYNE. That is right.

Senator BOREN. Put some equipment to work that is already there that is idle, for example.

Mr. PAYNE. That is exactly right.

Senator BOREN. Let me ask both Mr. Russell and Mr. Smith, you have commented on the alternative minimum tax. I think virtually all of you have commented on the alternative minimum tax. I would gather that any kind of tax relief of any kind that we could give, relief on the alternative minimum tax as far as you are concerned would really probably be a first priority and that you would feel that any additional credits that we might give, it would be very important that they did not fall back under the net of the alternative minimum tax to be taken away with one hand after being given with the other.

Is that a fair statement to say, that relief on the alternative minimum tax—let me ask maybe all of you from that point of view—that that would be a very strong priority as far as you are concerned?

Mr. SMITH. Senator, it is our number one priority. We estimate that about 80 percent of independents are impacted by the alternative minimum tax. It could be as high as 85 to 90, but we know it is high. So if you do not grant alternative minimum tax, all other incentives get debased.

For instance Section 29——

Senator BOREN. Right.

Mr. SMITH. We are for Section 29 but we do not get it fully because of AMT tax impact.

Senator BOREN. Yes, I understand.

Mr. RUSSELL. I think total eliminate of it as far as independents are concerned would be a big boost to the independent segment. The 80 percent with concur with. TIPRO would certainly concur with that particular elimination. But it has been devastating for the independent to lose money and still have to pay a tax on losses.

Senator BOREN. It is unbelievable and obviously many of you know of circumstances where that is the case. I think that this goes back to the committee not understanding and the Congress not understanding what it was doing when it passed this.

Mr. SMITH. I think you've got a representative poll at this table. I will tell you right now I am subject to the alternative minimum tax with a net operating loss.

Senator BOREN. With a net operating loss.

Mr. RUSSELL. So am I

Senator BOREN. You are too and I think——

Mr. PAYNE. We had close to a $20 million net operating loss in the second quarter.

Senator BOREN. Without starting to call names, including some on this committee, I certainly wish that some of my colleagues were here to hear this. I am going to—you can be sure once it is typed in our written transcripts, it will be shown by me to them to read. Because I think they had this image that these are people that are just making huge profits out here and are paying no taxes whatsoever; and therefore we have to have this alternative minimum tax to catch them up and make them pay something.

Here, the way it has been designed, you have people with net operating losses that are being caught up in this so-called minimum tax.

Mr. RUSSELL. We have not taken a poll in TIPRO, but I would suggest that probably a high percentage of the membership are in this same situation.

Senator BOREN. I wish we could devise a system where the Government would maybe share in the loss of our independent producers to the degree that they are still making you pay taxes.

Mr. RUSSELL. Right.

Senator BOREN. It is a situation that is if there was ever a case of something being improperly drafted this is it. I think most people, 90 percent of the Members of Congress, especially those from areas which do not have independent oil and gas producers, would be absolutely astounded with the idea that people would be having losses and paying alternative minimum tax.

This wellhead tax, the ad valorem proposals, and others that are being mentioned, I have heard it said that this tax really could not be passed on by the independent producer if it were implemented. Could some of you explain why that is the case?

Mr. GOODMAN. This is due primarily to the fact that independent producers are "price takers" and have virtually no market power if refiners decide to lower postings by the amount of the tax. At which point the tax becomes a wellhead tax on U.S. oil production rather than a tax on oil consumption.

Mr. RUSSELL. Well the independents are certainly not in the refinery business, nor do we have any other way to pass on any increase in cost or taxes or otherwise, particularly in oil and gas both. So any wellhead tax is just another burden that we have to bear.

Senator BOREN. This is really again firing and hitting the wrong target in terms of hitting our domestic independent producers especially. It just adds on to the——

Mr. PAYNE. I would like to add, Senator, that if we think that we have a growing dependence upon foreign oil, and if we do not like the decline that we are seeing right now in our production rate in this country, if we put a wellhead tax on in this Nation and we do not see price increases, you will really not like what you are going to see then, because you are going to see our dependence on imports and on production decline greatly accelerated.

Mr. GOODMAN. Senator Boren, just for your information, if a gross wellhead tax is imposed, it's impact triples as a percentage of net revenues. So whatever percentage it is of gross value that is taken at the wellhead, that impact on net income to the oil and gas producer virtually triples.

Mr. SMITH. May I add one final comment to that, Senator? That the asset base for the entire industry in this country right now cannot be more than about 35 or 40 percent of what it was 5 years ago, and that is not discounting real money. That is just in today's dollars.

Senator BOREN. Right.

Mr. SMITH. So if Congress was to enact a wellhead tax, that would no doubt bring the domestic industry down in the 20-25 percent range and that seems to me like poor policy. Even the dumbest farmer in the country knows to fatten up the pig before he slaughters it. [Laughter.]

Mr. RUSSELL. I think in summary I would have to say that here we are in a position where we need tax relief and there is indication that they are trying to put more of a tax burden on the domestic segment. I think this is totally intolerable.

Senator BOREN. Well I appreciate the comments. I understand. Obviously, I agree with what you have said. Let me just say I will share this with my colleagues, especially those from regions of the country where they do not have much experience with the economic of the oil and gas industry, and particularly the independent oil and gas industry.

I notice there are three Texans on this panel and we from Oklahoma are always glad to have a chance to talk with Texans and to learn from Texans. You know, my own family originated from Texas and then they realized the dream of every Texan, they got to move to Oklahoma. [Laughter.]

We are really glad to have had you and appreciate your patience with the scheduling problems we have today.

Our last panel, let me say last but not least—and obviously first in patience; I think a gold star should go by every name for having waited this long—Mr. Joseph Campbell, vice president, Drilling and Production Operations at Columbia Natural Gas, testifying on behalf of the American Gas Association, Mr. Campbell is from Charleston, WV; Mr. Sanford McCormick, president of Metfuel, Inc., testifying on behalf of the Section 29 Association; Mr. Stephen Lipman, president of science and technology division of Unocal

Corp.; and Mr. Mark Papa, senior vice president of Enron Oil and Gas of Houston.

We are very happy to have all of you with us. I am sure you will join me in being glad that I will receive your full statement for the record and let you summarize your comments. Again, I apologize to you for this situation. We are only about an hour and a half, or an hour and 45 minutes, later than you were due to be on this panel and I hope we have not disrupted your schedule unduly.

Mr. McCormick, why don't we begin with you and we will just go down the row. Again, I will try to withhold comments until each one of you is finished.

STATEMENT OF SANFORD E. McCORMICK, PRESIDENT, METFUEL, INC., TESTIFYING ON BEHALF OF SECTION 29 ASSOCIATION, HOUSTON, TX

Mr. McCormick. Thank you, Senator. My name is Sanford McCormick. I am the founder and President of Metfuel. It is a company that is involved in coalbed methane production. I want to say it is a real pleasure to be here. I have been in the oil and gas business since 1956 and started with an up and promising young oil man by the name of George Bush and I have seen a lot of ups and a lot of downs.

I want to say with all confidence that I have never seen anything that is as effective a stimulus for production as is the Section 29 credit. Now I am speaking only about coalbed methane, but my remarks really would apply equally to the other parts of it. I just am not qualified to comment on those.

We have heard a lot of talk today about the crisis that is upcoming or the one we are actually in. You commented on that, Senator Bentsen did, and everyone has. I just want to put my own little spin on it as they say. I have been working up some numbers and I thought I would put it in the perspective of another current problem Washington and the country is seeing, and that is the S&L crisis.

I think there is one clear similarity and one clear difference. The similarity is that I think the crisis in energy that we are looking towards in the next few years is every bit as predictable as the S&L crisis was 5 years ago. It is no secret it is going to happen; it is when and how severely. I think the dissimilarity is, it is going to cost a whole lot more than the S&L crisis. There are a lot of numbers. I just want to give you a few that will differ a little from some you have heard earlier today. Everyone has got their own figure.

My estimate is that we have seen in oil about a 25 percent decline since 1970 and we have heard the number of about 7-percent decline this year. My figures are that oil production will continue to decline so that we will be importing about 80 percent of our oil by the year 2000.

Now to put this in terms of cost, what we are looking at is a cost in the decade of the 1990's of $2 trillion for oil imports. That is about four times what they were in the 1980's. Another way of looking at it is that the annual cost of oil imports in the last years of the 1990's will equal the maximum most recent estimate of the total S&L bailout.

Now I do not think that requires any more elaboration except to say that anything that can be done through any reasonably cost-effective method to stimulate domestic production has got to be really seriously looked at. I am not here to say that the Section 29 credit in coalbed methane or anything else is the answer to the problem. I am saying that it is a proven well-established way of gaining a step on it, going in the right direction in a very cost effective way.

Let me say first that the basic nature of this credit, I think, is absolutely superb. I do not know who thought of it, but I think it is a marvelous credit; and with all due deference to some of the other suggestions that have been made here by other people about credits on drilling, credits on IDC's, I think that the credit on production, whether it be coalbed methane or, I might add, other types of resources is wonderful for a couple of reasons.

In the first place it does not cost the Government a penny unless there is actually production found and produced. And secondly, it is spread out over the life of the production and not all hit in the first year as would, you know, a credit on drilling or a credit on intangibles or whatever. I think it is really a marvelous type of credit and I think the results on coalbed methane have been very impressive.

In looking at what has happened, I would like to just very briefly summarize how I see it. Basically, most of the activity in coalbed methane is really a brand new industry. It really goes back only about 10 years, mainly 5 years. Most of the activity has been in two basins, the San Juan Basin in the Rockies and Black Warrior Basin in Alabama.

If the credit is not extended much of the very promising activity in those two areas will dwindle. But I think more important is the fact that the activity that is currently underway in the other basins in the country will for all practical purposes stop. I will give you one example later of our particular activities.

I do not have a map of the country. I should have brought it, but there is a map prepared by the Gas Research Institute that is the best guess available of potential coalbed methane reserves. It has a number of 400 trillion cubic feet. I think that is high, but it is a guess. The University of Colorado came out recently with a number of producible coalbed methane reserves as opposed to potential of 100 trillion.

Now this compares with a number that about 8 years ago was zero. A potential gas reserves study done by the USGS 8 years ago came out with a potential coalbed methane reserves of precisely zero. So what I am saying is, here is a potential domestic reserve in this country. It is obviously clean burning and everything else that has that type of potential.

Senator BOREN. Geographically wide spread.

Mr. MCCORMICK. All over. Almost all of the producing States. I am sorry I did not bring the map. I thought incorrectly that someone else would.

I would like to summarize the two real benefits of this. Number one, the local community. There is a study written by the University of Alabama that shows the benefits for the local community in and around Tuscaloosa. It is pretty impressive—$4 billion of expenditures; 13,000 jobs created over a 5-year period; $1 to $2 billion in local taxes.

That same impact could be had in many other communities in this country. By the way, much more can be said in the San Juan which is larger.

I will tell you the other important benefit I see. I have talked about this import problem. It is hard to get a handle on something with that many zeros. At least for me it is. Let me put it down to something simpler. One trillion feet of gas is the equivalent of about 160 million barrels of oil. So that each trillion feet that is domestically discovered replaces or comes in lieu of 160 million barrels of imports which at today's price is $3 billion; and over the 10 to 20 years will probably be $4 to $5 billion.

As I say we have a potential of 100, maybe more, trillion feet of coalbed methane gas to be discovered. This could save as much as $500 billion from oil import costs.

Now let me talk a little about our little company, Metfuel. Metfuel is a company that I founded with some other people in the Fall of 1988. I can tell you very simply and clearly that we are sort of a pure case. Our company would not have been founded if it were not for the coalbed methane credit, the Section 29 credit. We simply could not have attracted capital. I would not have even tried, because it simply was uneconomic without the credit.

I have furnished—and I would be happy to give you a copy—to Secretary Watkins our economics with and without the credit. Basically, it shows a rate of return before of about 9 percent; after in the high twenties. In other words, from totally unacceptable to acceptable. And we have been able to attract enough capital to drill about 500 wells at a cost of $200 million. And I repeat, none of this, not 1 dollar, would have been spent, and no reserves would have been found.

Now, activity is fine but activity does not solve energy problems; results do. This money we have spent has found somewhere between half a trillion and a trillion feet of gas. In other words, we are getting up towards this $160 million—barrel oil field, which could save $3 to $5 billion of imports.

The point is, this little story of our little company, Metfuel, could be repeated hundreds of times in this country, and will be over the next decade if this credit is extended. If it is not, I can assure you there will be no coalbed methane activity in these other basins, at least until the price of gas goes up very substantially. We are looking then at several years from now. By that time this crisis is going to be really serious.

I will give you one little example. We have a second project we have acquired in Wyoming. It is a basin that isn't even on the map of potential coalbed methane in the whole country. It has also the potential of half a trillion to a trillion feet of gas. We will drill a couple wells this year, but if the credit is not extended we will drop it like a hot potato, because there is no way that it could be close to economic without the credit.

Thank you very much, Senator. I am sorry to take a little more of the red light than I was supposed to. I appreciate it.

[The prepared statement of Mr. McCormick appears in the appendix.]

Senator BOREN. It was very good points and I appreciate your making them. I especially appreciate the fact that we simply would not have this industry and these additional reserves without this credit. I think it is very important to underline that.

I would appreciate it if you do have a map if you could furnish it for us for the record.

Mr. MCCORMICK. Yes, sir.

[The map appears in the appendix.]

Senator BOREN. Because I think that it is important that our colleagues understand that this is a geographically widespread resource that has potential for great development, help in terms of energy security, and domestic economic activity as well virtually all over the country. It is a good point.

Mr. Papa?

STATEMENT OF MARK G. PAPA, SENIOR VICE PRESIDENT OF OPERATIONS, ENRON OIL AND GAS CO., HOUSTON, TX

Mr. PAPA. Mr. Chairman, I am Mark Papa, Senior Vice President of Operations of Enron Oil and Gas Company. Thank you for the opportunity to present this testimony on the importance of reducing our dependence on foreign energy sources by restoring the Section 29 tax credit for tight gas reservoirs.

Enron Oil and Gas is based in Houston, Texas and is one of the Nation's largest independent exploration and production companies. We operate in most hydrocarbon basins in the lower 48 States and produce gas from both conventional and tight gas sand wells.

Before I proceed further, let me define what tight gas is. Tight gas is produced from reservoirs having low permeability or transmissibility. Because these reservoirs exhibit a lower quality than that of conventional reservoirs, tight gas wells must be stimulated by hydraulic fracturing which is a costly way to enhance well productivity.

In a conventional well the primary costs involve drilling and running pipe into the well bore. In a tight gas well an additional cost of fracture stimulation is incurred. Often the fracture stimulation costs as much as drilling the well. Therefore, tight gas is more costly to develop than conventional gas. The Section 29 credit, if restored, would provide an economic incentive to producers to produce these tight gas reserves.

We also want to emphasize that we are not requesting a new incentive credit related to tight gas production. We are merely requesting a restoration of the credit that was inadvertently terminated for tight formation gas because of deregulation and FERC orders.

We believe a restoration of the Section 29 tax credit for tight formations is in the national interest for the following reasons: First, tight gas represents approximately one-fifth of the Nation's estimated remaining gas reserves. So the potential impact from an effective tight gas production incentive is large. Increased development of tight gas will reduce our Nation's dependence on imported energy and represents a reliable source of supply.

Second, the Section 29 tax credit has proven effective in stimulating reserve and deliverability growth regarding coal seam gas and, in the past, tight gas. In short, the incentive works.

Third, increased natural gas deliverability will provide environmental benefits since gas is the cleanest burning hydrocarbon fuel.

Previous panelists have commented regarding the effects of depressed natural gas drilling for new reserves. Underscoring this concern, 40 percent of the Nation's current gas production comes from wells completed subsequent to 1985. Since such a high proportion of the Nation's supply comes from recent vintage wells, continuation of the current low drilling levels will exacerbate the Nation's gas supply and import problems.

Natural gas found in tight formations is an increasingly important component of our Nation's energy resource portfolio. A 1988 DOE study indicated that tight gas reserves comprise approximately 180 trillion cubic feet or one-fifth of estimated U.S. reserves. Tight gas is found in 21 States and is currently produced in 16 States as diverse as Texas, New York, Oklahoma, Louisiana and Ohio.

We believe the Section 29 tax credit incentive, if properly revised and reinstated, is the best vehicle to stimulate domestic natural gas production and reserves. Unlike an across-the-board credit for all domestic drilling, the Section 29 credit is activated only if a well is successful. If the well is unsuccessful, all of the risk of drilling stays with the producer and no credit is available.

Additionally, the Section 29 credit will focus industry activity on a large proven resource base. There is no question that these tight gas reserves exist. Similarly, the effectiveness of the Section 29 credit has been recently confirmed. Coal seam gas is currently eligible for the credit and resent results from the San Juan Basin in New Mexico and Colorado show that the tax incentive has stimulated a mini boom in coal seam gas drilling in this area, with positive national energy results.

We estimate that 1200 coal gas wells will be drilled in this basin alone by year end 1990 generating 3.6 trillion cubic feet of reserves with a peak deliverability of over 700 million cubic feet per day. Most of this drilling is a result of the Section 29 tax incentive.

In the past this tax credit has also stimulated tight sand drilling, which is a much larger resource base than coal gas. Our analysis of 1970 to 1990 drilling activity in the tight Cotton Valley formation in east Texas indicates significant relative increases in tight formation drilling during periods where price supports or tax incentives were available.

This data indicates that Section 29 incentives are effective and Enron Oil and Gas supports the Section 29 legislation proposed by Congressman Andrews, H.R. 5351, and Senator Domenici, S. 2288. Enron oil and gas is active in several tight sand areas in Texas, Utah and Wyoming. We are basically spending our available cash flow to develop new natural gas supplies. If tax credit incentives for developing tight gas ends were reinstated, any cash flow generated from the tax credits would be spent drilling tight sand wells. With a properly focused tax credit Enron Oil and Gas estimates we would drill up to 500 additional wells within 5 years. The economic benefits of a tax credit would provide the incentive to commence and sustain such a program.

Thank you.

Senator BOREN. Thank you very much.

[The prepared statement of Mr. Papa appears in the appendix.]

Senator BOREN. Mr. Lipman?

STATEMENT OF STEPHEN C. LIPMAN, PRESIDENT, SCIENCE AND TECHNOLOGY DIVISION, UNOCAL CORP., BREA, CA

Mr. LIPMAN. Thank you, Mr. Chairman. My name is Stephen Lipman. I am president of the Unocal Science and Technology and Energy Mining Divisions. I appreciate the opportunity to be able to present our comments. We have submitted written comments. Some of those have dealt with conventional fuel. So I will not duplicate what a lot of what has already been said today. We concur in general with that.

Senator BOREN. We will receive all of them for the record.

Mr. LIPMAN. All right.

The one point I would like to emphasize is that Unocal does believe that any incentives adopted or extended are meaningless without a variable import fee keyed to a realistic floor price for some price stability.

What I would like to talk about now is two alternative energy developments which Unocal has been the leader in developing. Geothermal energy and oil produced from shale, both important nonconventional sources of energy.

Our national attention that once focused on alternative energy has declined along with the oil prices. We firmly believe that the nonconventional fuels will become important in the near future because of our increasing dependence on foreign oil. Geothermal energy is environmentally safe and current projects which benefited from the energy tax credit are successfully competing at today's prices.

However, more technological improvements are needed to reduce the costs of new projects. Power generated from geothermal energy benefits the Nation in many ways; and we should not be limiting its use by letting the energy tax credits expire. Therefore, we believe that in order to further this important new technology and see new projects move into commercial operation, the existing energy tax credit should be extended.

Shale oil is also an important new energy source and is one of the best alternatives to crude oil for transportation fuels and lubricants. If given the opportunity for continued development, technological achievement could make oil derived from shale an economically viable alternative in the not too distant future. We believe there are some very important reasons for the United States to continue its support of oil shale development.

First, oil shale is abundant. Many are surprised to learn that our Nation has as much recoverable shale oil as OPEC has in recoverable crude oil. Second, we found that the upgraded shale oil is a superior feed stock for conversion to transportation fuels and lubricants. We can convert 100 percent of the syncrude into transportation fuels without the residue of heavy bottoms as with conventional crude oil. Third, after investing $1.2 billion of our own money, Unocal is close to defining the technological parameters at its Parachute Creek Oil Shale Project. But it has been an economic strain on our company.

Last year we increased our production by 40 percent and we reduced our costs by 23 percent, but we still lost $36 million. We have had to write off the entire project off our company's books. And our continued efforts for the future are uncertain.

Nevertheless, we see a lot has been accomplished. Each year we have seen the loss that we have incurred each year has come down and we are hopeful this year that we will have a better year than last year.

We have introduced into the record two letters from the Office of the Assistant Secretary of Defense detailing that Agency's interests in shale oil as a secure alternative source of jet fuel. In fact, just this week the defense fuel supply center solicited proposals for a supply of jet fuel derived from shale oil.

Our key point today is that Section 29 of the Internal Revenue Code was originally enacted to encourage production from oil shale and other nonconventional energy sources. Unfortunately, because of the restrictions in Section 29, Unocal has been unable to take advantage of this Section. Despite the technical improvements we have been making in the last few years we cannot continue to keep operating at a loss.

Therefore, Unocal urges modification to Section 29 in order to help its efforts to improve oil shale technology. We proposed a three-year moratorium on the application of three restrictions imposed by Section 29.

First, during the 3 years the credit should not be offset by any past energy investment tax credits. Second, the credit should not be reduced by tax exempt pollution control bond financing. And lastly, as you have heard others say, the credit or any tax incentives under consideration today should be made available to all taxpayers including those subject to the Tax Code minimum alternative tax. Otherwise, these incentives will not achieve the desired response.

This 3-year window of opportunity would enable Unocal to make further technological progress.

Thank you for allowing us to testify.

Senator BOREN. Thank you very much, Mr. Lipman.

[The prepared statement of Mr. Lipman appears in the appendix.]

Senator BOREN. I guess we close on a frustrating note in that we have another vote on the floor. But I think we should be able to get through with your testimony, Mr. Campbell, before I have to go back over there. Again, I apologize for keeping you so long.

STATEMENT OF JOSEPH E. CAMPBELL, VICE PRESIDENT, DRILLING AND PRODUCTION OPERATIONS, COLUMBIA NATURAL RESOURCES, INC., TESTIFYING ON BEHALF OF THE AMERICAN GAS ASSOCIATION, CHARLESTON, WV

Mr. CAMPBELL. I will summarize and keep it brief. Mr. Chairman, I am Joe Campbell, vice president of Columbia Natural Resources. I am here today on behalf of the American Gas Association.

The natural gas industry strongly supports both an extension of the nonconventional fuels tax credit and the restoration of the tight sands credit. The 1988 DOE study estimates that one-quarter of the remaining recoverable reserves in the lower 48 were 259 trillion cubic feet, lie in nonconventional sources.

As you know nonconventional sources include Devonian shale, coalbed methane and tight formations. Is Section 29 fulfilling Congress's goal of increasing gas production from nonconventional resources? The answer is unequivocally yes. To give some perspective on the extent to which the credit has encouraged production let me use Oklahoma's gas use as an example. In 1989 Oklahomans consumed 448 BCF of natural gas. Last year nonconventional gas production in the United States encouraged by Section 29 credit would have satisfied the equivalent natural gas needs for the entire State of Oklahoma four times over.

However, the vast majority of these nonconventional reserves cannot be produced economically for less than $3 in MMBtu, well above the current market price. Importantly, the credit applies only as sufficient price incentives in the market place are lacking. Therefore, elimination of the credit now when market prices are still lagging would jeopardize the production of a significant portion of our remaining natural gas reserves.

The credit is a true production credit. It applies only after gas reserves have been developed and are producing. That means that all the risks inherent to exploration and development are borne by the producer. The AGA supports extending for 2 years the credit for all nonconventional fuels and restoring the credit for tight sands.

Also, AGA suggests that FERC orders which have negative implications for tight sands be rectified. For example, FERC's Order 523 in effect deregulates released gas retroactively to the date of the Decontrol Act, thus eliminating the tax credit for otherwise eligible gas.

Since others have discussed the importance of the credit for coal seam and tight sands I would like to furnish my comments on Devonian shale which is particularly important to the Appalachian Region where CNR operates.

Gas contained in Devonian shale underlies an area of approximately 23,000 square miles—more than six times the size of the State of Pennsylvania. Two thirds of Devonian shale gas is in the Appalachian Basin, the remainder is in Michigan and the Illinois Basins.

DOE estimates that the total gas in place for Devonian shale ranges between 200 and 2,500 trillion cubic feet of gas, with only 10 trillion feet recoverable at $3 in MMBtu. Just 1 trillion cubic feet of natural gas recovered from the Devonian shale would mean 500 additional wells per year for the next 10 years, assuming an average of 200 million cubic feet of reserves per well. Such a large number of wells could have a profound positive impact on the region where the wells were drilled.

In addition to positive local economic affects, natural gas from Devonian shale is valuable to the Nation because it can help reduce our reliance on foreign oil. Devonian shale development can be particularly important to helping reduce the eastern seaboard's reliance on foreign energy sources. The Devonian shales of the Appalachian basin are geographically situated to be an ideal gas supplier to new energy projects on the eastern seaboard, including cogeneration and independent power projects.

The low volume, low pressure production from Devonian shale has a very long production life. In fact, CNR has several Devonian shale wells which have been in production for over 80 years.

In my remaining time, quickly let me summarize why the American Gas Association supports the extension of Section 29 tax credit. First, it has been demonstrated that the tax incentive is an effective means of stimulating gas reserve development. During the past 10 years my company alone added 29.5 billion cubic feet of shale gas to its reserves; and we plan to drill an additional 171 Devonian shale wells this year.

Second, a tax credit is necessary to justify the economics for wells that have a very low production rate and a very long production life. Wells that produce less than 10 Mcf a day can be marginal to operate, but in the case of the Devonian shale it is not uncommon to see a well average 5 Mcf a day for 20 years.

An extension of the tax credit will greatly influence a continued production of these stripper wells. Third, increased use of natural gas could make market reduction dramatic reductions in the Nation's of the procurers to such environmental problems as global warming, acid rain, ground level ozone formation.

Increasing reliance on natural gas can help us attain our clean air goals while reducing the need for stringent emissions. Passage of AGA's Section 29 recommendations will help to ensure an adequate supply of natural gas to support increased demand.

Finally, domestically produced natural gas, which is Section 29 credit encourages and reduces our Nation's reliance on foreign oil.

For all of these reasons, I respectfully urge the committee to reinstate the credit for tight sands and to extend the credit for all nonconventional fuels. That will allow the Nation to continue to enjoy the clean air and energy security benefits provided by these reserves.

Thank you, sir.

Senator BOREN. Thank you very much.

[The prepared statement of Mr. Campbell appears in the appendix.]

Senator BOREN. You have all made a very strong and excellent case for maintaining, reinstating, and broadening, indeed, the Section 29 treatment.

I apologize. I do have to go to vote. I am not going to ask that you come back. We have inconvenienced you enough. I will keep the hearing record open so that any of you or any of our other witnesses can file additional comments if they would like to or if members would like to file additional questions to have you address.

I think the evidence that you have given is extremely important. The importance of Section 29 I do not think can be overestimated in the effort to try to make us more energy independent and also in many cases to help with environmental problems in this country as well. We are talking about the Clean Air Act. It would be ironic, indeed, if in the course of time in the same Congress in which we were discussing the Clean Air Act that we would take action that would discourage further improvements along this line by not reinstating Section 29.

You have made some excellent points. I appreciate them very much. I think if the American people are not awakened, and my fellow Members of Congress are not awakened, by the kind of testimony that we have heard today about the economic threat posed to our country. Then they won't wake up in the world in which we are living, an economic threat is indeed a threat to our national security because more and more our influence in the world is going to rest upon our economic strength.

If we are not awakened to action by what we have heard today I do not know what in the world would cause us to wake up and begin to take action in the right direction to stimulate domestic energy production in this country. I think the comments that were made here about the S&L problem, about looking ahead at the magnitude of the problem we face in this area and seeing with certainty exactly what we are going to face if we do not take action now, I hope will also strike a responsive chord with some of my colleagues.

Congress, the administration, everyone involved in public policy over the last decade is now scrambling to point the finger of blame as to who was asleep at the switch as the S&L crisis began to develop. Let us hope that instead of arguing after the fact, and after the damage has been done, about who was asleep at the switch, that instead we will wake up and do something about this very serious problem that we face.

So I thank all of you for being here. We will keep the record open. Again, thank vou for your patience.

[Whereupon, the hearing was adjcurned at 1:57 p.m.]

APPENDIX

Additional Material Submitted

Prepared Statement of Representative Michael A. Andrews

Mr. Chairman, thank you for inviting me to testify before your subcommittee on the important energy issues facing our country today. I applaud your leadership in this area, and have enjoyed working with you to accomplish our similar goals.

We will listen today to industry experts account for the devastating effects that OPEC has had on domestic exploration and production, which are increasingly evident in light of the recent events in the Middle East between Iraq and Kuwait. We will also hear the difficulties faced by our independent oil producers in obtaining capital with which to drill.

I have come before your subcommittee in the past to express my hope for a national energy policy and to detail several bills I have introduced which form the framework of a national energy policy, beginning with a resolution calling for a defined core supply of domestic energy (H.Con. Res. 34). I also have introduced a variable import fee (H.R. 659) and a bill we jointly introduced to provide tax incentives for domestic oil and gas exploration, development and production (H.R. 658, S. 234). I still believe that the components of these bills are critical to the achievement of energy independence for the United States. In particular, relief under the minimum tax will significantly assist independent producers in obtaining the capital they so desperately need to continue exploration and development.

I have just this week introduced additional incentive legislation, H.R. 5351, the Nonconventional Fuels Credit Extension and Modification Act of 1990. This bill is similar in scope to the bill introduced by Senator Domenici, S. 2288. It will extend section 29 of the Internal Revenue Code for two additional years and will reinstate the tight sands tax credit under section 29. Due to a recent Supreme Court decision, in addition to the deregulation of natural gas by the Natural Gas Wellhead Decontrol Act of 1989 and recent FERC orders, virtually all tight sands gas is currently ineligible for the section 29 credit. My bill removes the price regulation requirement from the section 29 credit, thus allowing tight sands gas to once again qualify under the credit.

As you know, over the past ten years since the credit was first established, section 29 has been responsible for a dramatic increase in nonconventional fuel production, primarily the production of tight sands gas, gas from Devonian shale and coalbed methane. A recent study by the of Mines nchool of Mines now estimates that economically recoverable coalbed methane reserves at 95 trillion cubic feet. The credit has facilitated the production of methane gas from landfills and will further the development of gas from these sources as well as help unlock the vast reserves of gas found in geopressurized brine, tight sands, and Devonian shale.

Nonconventional fuels which receive incentives under section 29 are found in over twenty states, including New York, Michigan, Ohio, Pennsylvania, Virginia, West Virgina, and yes, in Oklahoma and Texas too. These fuels are found in states not traditionally viewed as critical to energy production. Yet nonconventional fuels represent a growing percentage of domestic gas production.

The nonconventional fuels credit encourages clean fuels. Having just completed action on the Clean Air Act, it is imperative that Congress stimulates the production of cleaner fuels. Natural gas found in tight sands formations and Devonian shale does not adversely affect global climate changes by way of the greenhouse effect. Natural gas emits virtually no sulfur dioxide. The credit encourages companies to capture methane in coal mines and landfills, thus reducing the effect methane seepage may have on global climate change.

Given the current budgetary climate, it will not be easy to pass into law any new incentives or relief from the minimum tax. However, we must not give up. We must work on a bipartisan basis to achieve some relief for energy production.

Mr. Chairman, I look forward to working with you and others in both the Senate and the House to achieve these goals. I would be happy to answer any questions you might have.

Prepared Statement of Senator Jeff Bingaman

I commend the Chairman of the Subcommittee on Energy and Agricultural Taxation for holding this hearing today. My remarks are specifically directed toward the testimony by one of your panels on Section 29 of the Internal Revenue Code of 1986. Section 29 provides a tax credit for certain fuels produced from unconventional sources, including several categories of natural gas production. That important tax credit expires at the end of the year.

This tax credit was originally established in 1980 to provide an incentive to produce energy resources from new, less established sources. The fuels that would qualify for this credit include: oil produced from shale and tar sands; gas produced from geopressurized brine, Devonian shale, coal seams, a tight formation, or biomass; liquid, gaseous, or solid synthetic fuels produced from coal, qualifying processed wood fuels, and steam produced from solid agricultural by-products. These fuels constitute an important resource for our energy future.

The extension is warranted to ensure continued development of our fossil fuel resources. At a time when imports of crude oil out-pace domestic oil output and when our domestic production is at alarmingly low levels, it is essential that we provide incentives to increase natural gas reserves and deliverability, thereby ensuring a viable domestic oil and gas industry. The incentive provided by the non-conventional fuel tax credit will help accomplish this goal.

The tax credit extension is important to my constituents in New Mexico. One of the most significant coal seam methane finds in the nation is located in the San Juan Basin in Northwestern New Mexico. It is estimated that 1200 coal gas wells will be drilled in this basin by the end of this year, generating 3.6 trillion cubic feet of reserves. This resource has provided new jobs and opportunities to the people of San Juan county and a reliable source of gas to serve the area and the Western United States.

In summary, by acting to keep the Section 29 tax credit, we lower energy imports and reduce natural gas prices, provide environmental benefits from the additional supplies of a clean burning fuel, and further the development of new technologies in drilling and well completions. Our nation's future depends on a reliable domestic energy supply at a reasonable cost.

If we take action to reestablish Section 29 tax credits, we take one important step toward meeting our energy security needs.

Prepared Statement of Senator David L. Boren

I have called this hearing today to once again examine the dramatic and continuing decline in U.S. energy production. This is not the first time this committee has addresses this issue. I have been sounding the call for a clear and practical energy policy including domestic production incentives since I came to the Senate in 1979.

Let's just review for a moment what has happened since 1985. The number of rotary rigs operating in the United States has declined from an average of 1,980 in 1985 to an average of 952 through the first six months of 1990 (see chart No. 1). That is over a 50% decline in less than 5 years. Since 1982, when the rig count was over 4,700, the United States has suffered an 80% decline in active rigs looking for new domestic reserves of oil and gas. In fact 1989 was the lowest average rig count since World War II.

How does a declining rig count affect our energy security? One look at imports as a percentage of total U.S. petroleum consumption can answer that question (chart No. 2). The U.S. is now importing over 52% of our petroleum needs. For the first time in our nation's history we are importing more energy from abroad than we are producing here at home. Imports today are higher than during both the Iranian Crisis in 1979, or the Arab Oil Embargo in 1973. And yet no one seems concerned. For example, when was the last time anyone in this room saw an advertisement for a car that stressed fuel economy?

Then there are those who suggest that rising imports don't matter. They say we are not likely to see in the 90's supply disruptions like we saw during the 70's. Well, where do our imports come from? Since 1985 imports from Persian Gulf producers have increased 450% (see Charts Nos. 3 and 4). Today almost 25% of our oil imports come from Arab OPEC countries. Have we not learned the lessons of the 1970's? If anyone doubts our energy security is threatened they need only look to the events of the past week. While Iraq, with a total military force in excess of million people, has massed its forces along the Kuwait border, the price of crude oil has jumped almost $5 per barrel. What would happen to the price of oil, and all energy, if that situation erupted into a shooting war? What would happen if Iraq didn't stop with Kuwait but continued south to challenge the United Arab Emirates or possibly even Saudi Arabia? When will we take the steps necessary to preserve some measure of domestic energy security?

I have long advocated price stability as an essential element of any national energy policy. I have in the past introduced legislation that would establish a variable import fee to be assessed on all imported oil. More recently I have proposed a "Flexible Floor" initiative that would provide incentives for domestic producers if the world price of crude oil fell below certain levels. Specifically, this proposal would:

(1) enact a production credit for marginal wells equal to 1% of the cost of production for every $1 the world price is below $22 per barrel. For example, if the world price was $15 per barrel, a 7% credit would apply. The credit would be fully creditable against the alternative minimum tax;

(2) suspend Intangible Drilling Costs and percentage depletion as preference items for the alternative minimum tax when the world price of crude oil is below $22 per barrel;

(3) provide a variable percentage depletion rate tied to the world price of crude oil: when the price of crude oil is over $22 the depletion rate would be 15%, and when the price of oil is below $22 the depletion rate would be 30%;

The fact remains we must take steps now to preserve what is left of our domestic energy industry. During the past 7 years over 6,000 oil and gas operators have gone out of business and closed their doors. But for the dramatic decline in price of crude oil in 1986-87, we may not have had an S&L crisis. We must come to the realization that cheap energy today will ultimately exact a terrible cost on our economy in the future. One estimate of our energy trade imbalance, provided to this committee by Dr. Jess Koontz, Vice President-Economic Analysis, Grace Energy Corporation, shows the cost of oil imports rising to $97 billion a year in 1995. As we worry about the impact of our national debt on our children and grandchildren, so must we worry about the future burden of our failure to establish a national energy policy today and preserve our domestic energy industries.

I look forward to hearing from our witnesses today. I know that they will all offer words of encouragement and advice. I only hope our colleagues will heed their advice.

CHART NO. 1

Number of Rotary Rigs Running in the U.S.

(Yearly Averages)

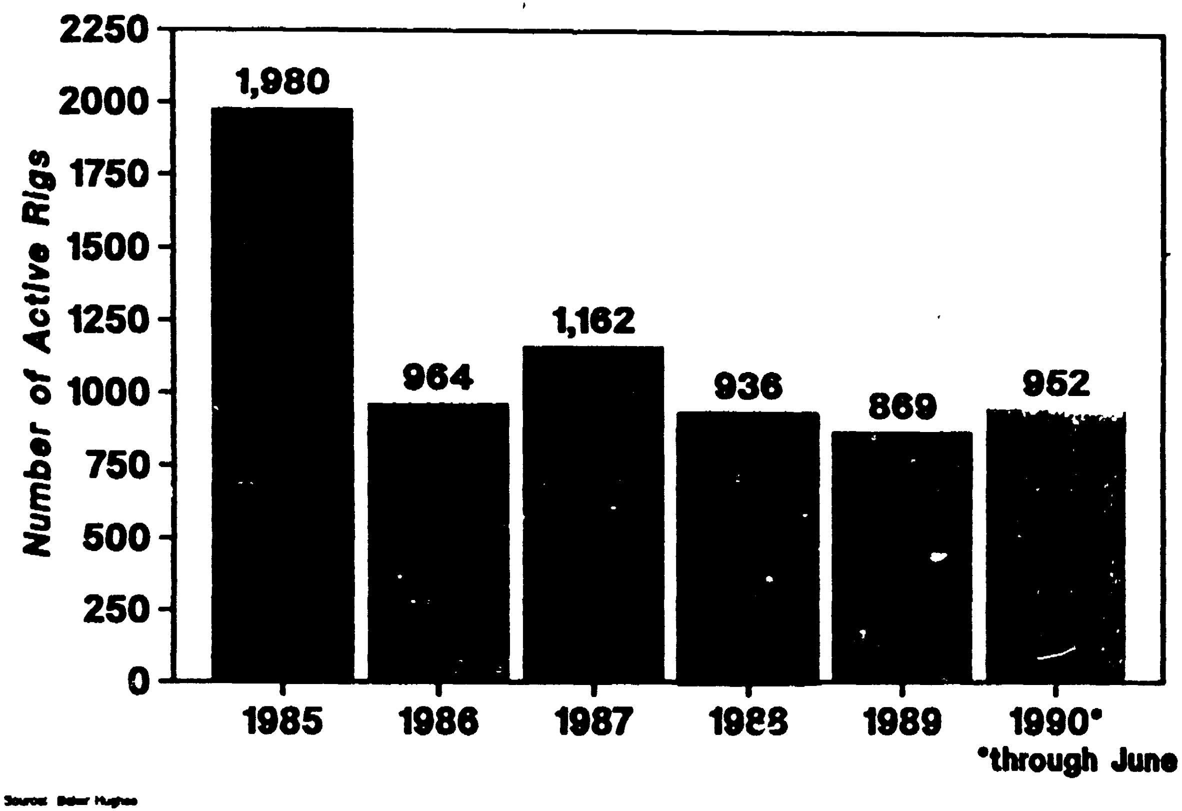
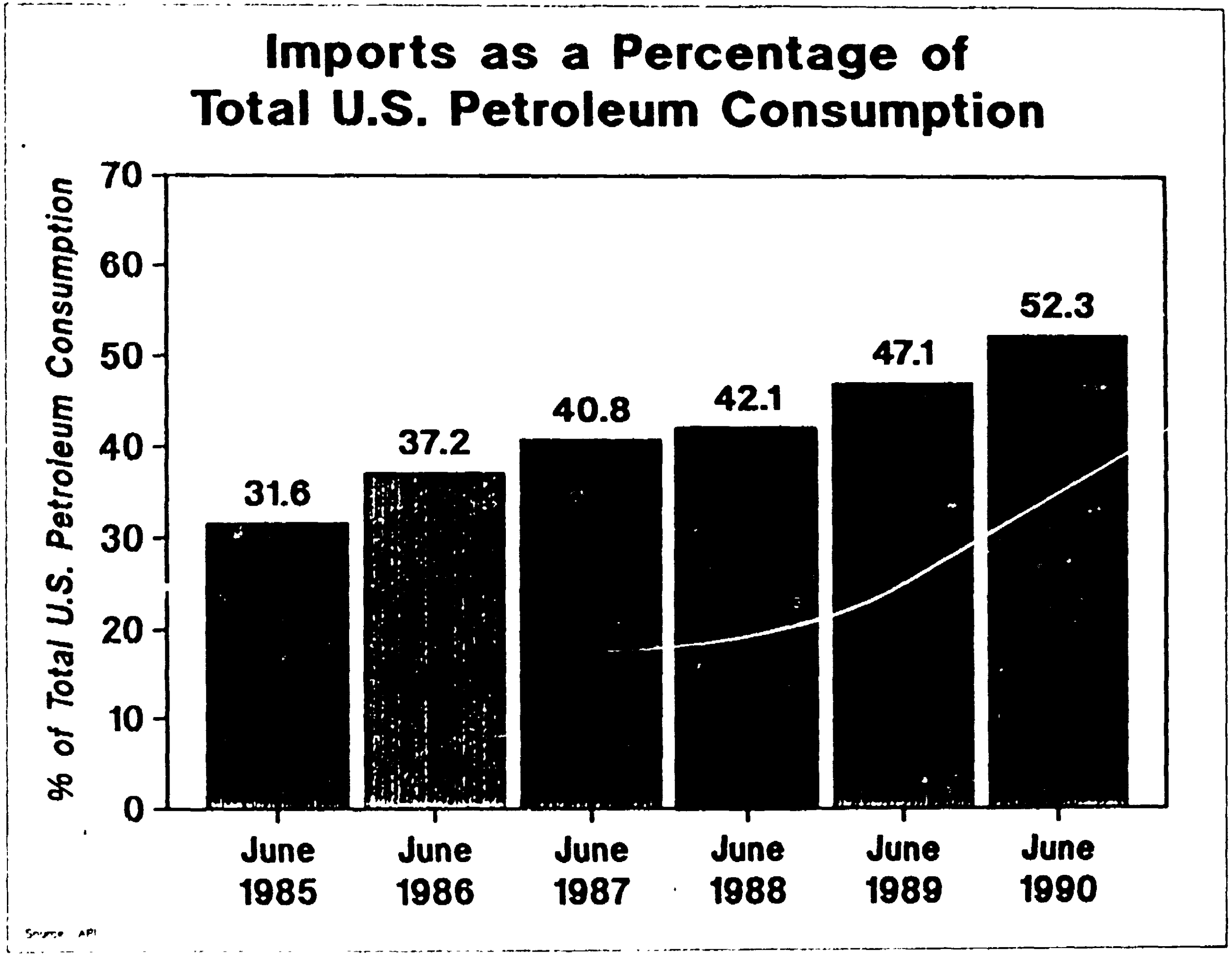


CHART NO. 2


Imports as a Percentage of
Total U.S. Petroleum Consumption
% of Total U.S. Petroleum Consumption
70
60
50
40
30
20
10
0
31.6
37.2
40.8
42.1
47.1
52.3
June 1985
June 1986
June 1987
June 1988
June 1989
June 1990
Source: API

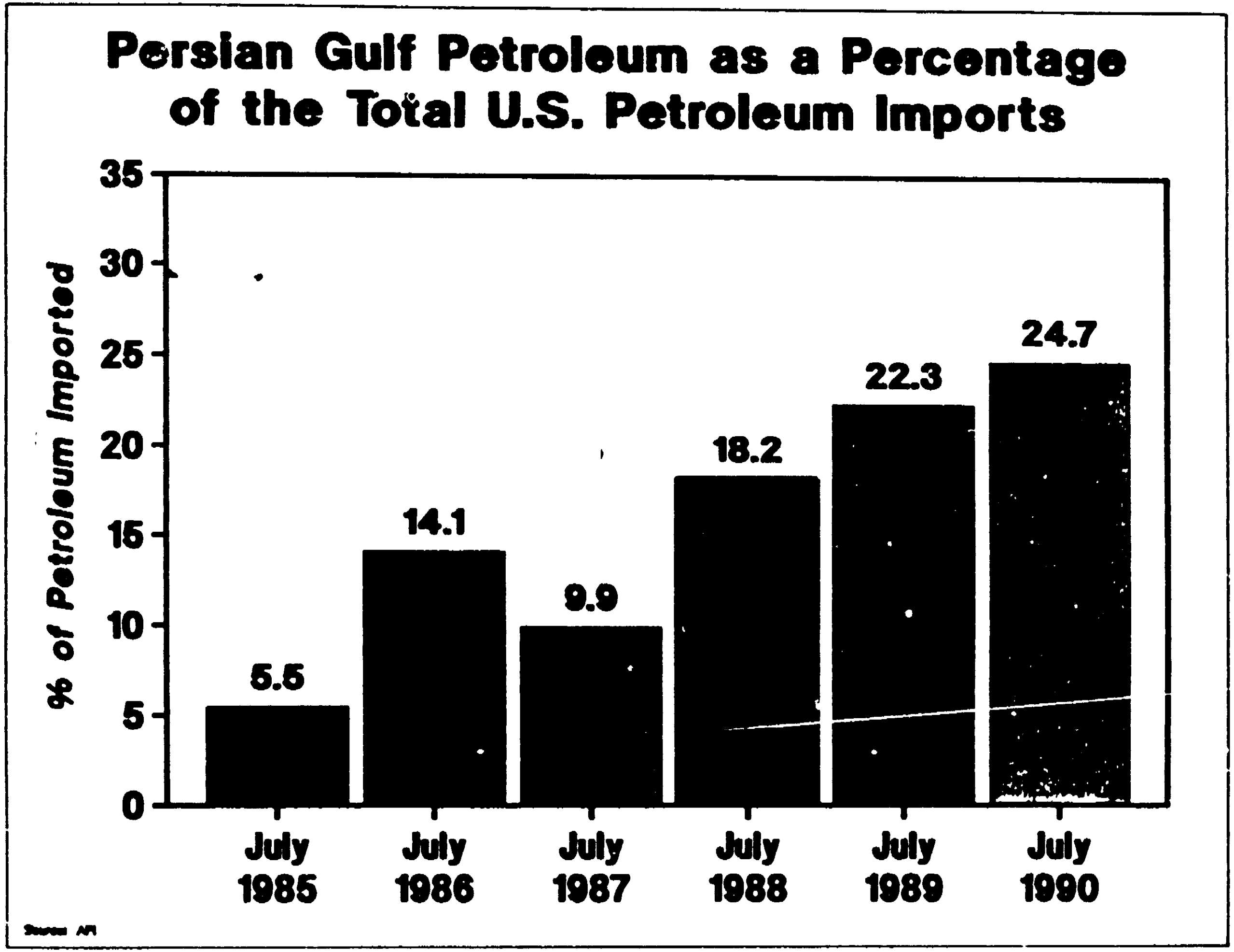

Persian Gulf Petroleum as a Percentage
of the Total U.S. Petroleum Imports
% of Petroleum Imported
35
30
25
20
15
10
5
0
5.5
14.1
9.9
18.2
22.3
24.7
July 1985
July 1986
July 1987
July 1988
July 1989
July 1990

CHART NO. 3

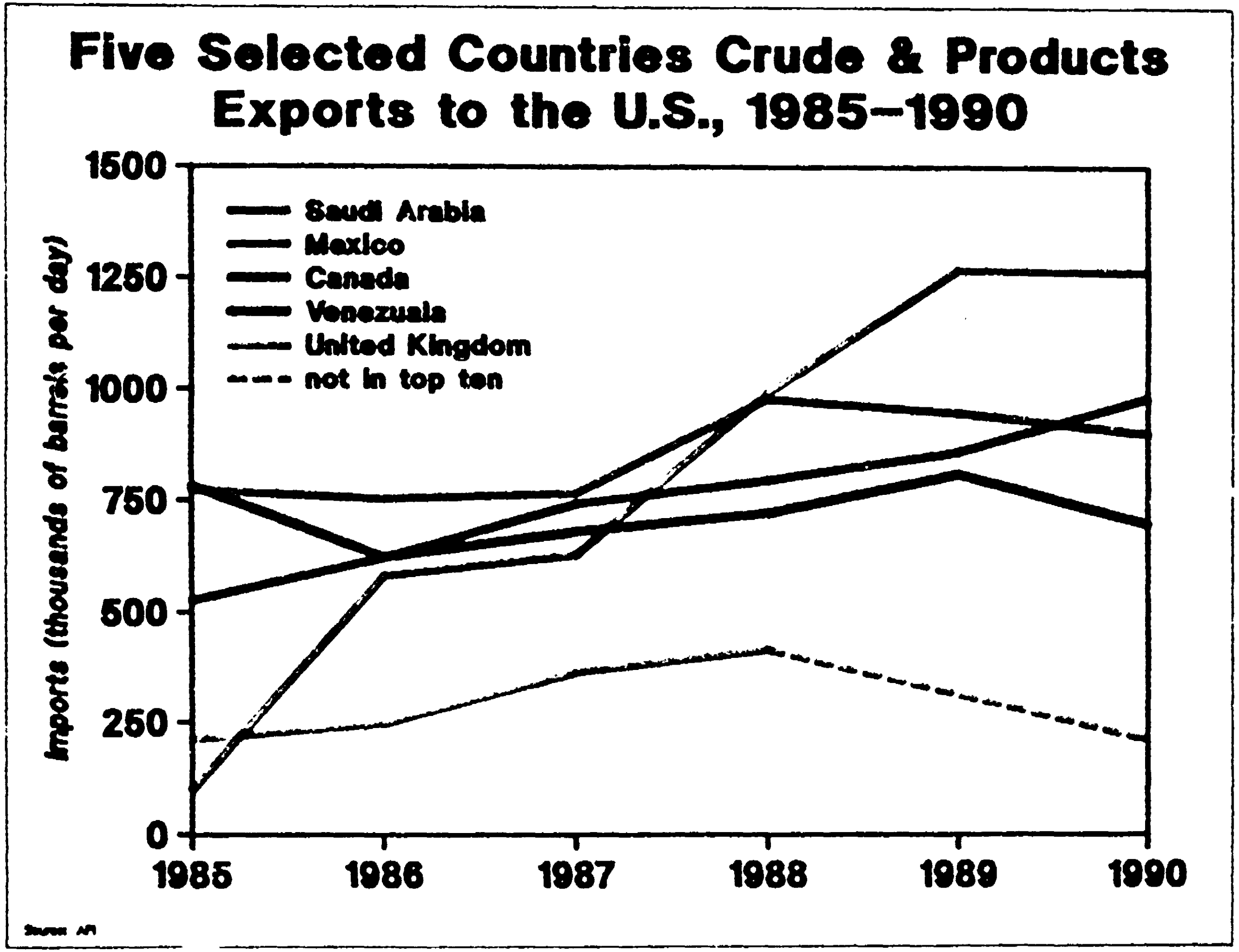

Five Selected Countries Crude & Products Exports to the U.S., 1985–1990
Saudi Arabia
Mexico
Canada
Venezuela
United Kingdom
not in top ten
Imports (thousands of barrels per day)
1500
1250
1000
750
500
250
0
1985
1986
1987
1988
1989
1990
Source: API

CHART NO. 4

[JOINT COMMITTEE PRINT]

PRESENT LAW AND PROPOSALS RELATING TO INCREASING DOMESTIC ENERGY PRODUCTION AND RESERVES

SCHEDULED FOR A HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AGRICULTURAL TAXATION

OF THE

COMMITTEE ON FINANCE

ON JULY 27, 1990

PREPARED BY THE STAFF

OF THE

JOINT COMMITTEE ON TAXATION

JULY 26, 1990

U.S. GOVERNMENT PRINTING OFFICE

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CONTENTS

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INTRODUCTION

This pamphlet,[1] prepared by the staff of the Joint Committee on Taxation, provides a discussion of various current and proposed tax provisions intended to increase U.S. energy production and reserves. The Senate Finance Subcommittee on Energy and Agricultural Taxation has scheduled a public hearing on that subject on July 27, 1990.

The first part of the pamphlet is an overview of tax provisions relating to the energy industry and a summary of the relevant proposals which are being considered. The second part is a description of specific tax provisions and proposals relating to energy production and reserves, including present law, the Administration budget proposals, Senate legislative proposals, and analysis of related issues.

[1] This pamphlet may be cited as follows: Joint Committee on Taxation, *Present Law and Proposals Relating to Increasing Domestic Energy Production and Reserves* (JCS-23-90), July 26, 1990.

tion of each of the credits by or before the end of 1988. The Technical and Miscellaneous Revenue Act of 1988 (the "1988 Act") extended for one year (through 1989) the credits for solar energy, geothermal energy, and ocean thermal property. The Omnibus Budget Reconciliation Act of 1989 (the "1989 Act") included an additional nine-month extension of these three credits (through September 30, 1990).

A production credit equal to $3 per BTU equivalent of a barrel of oil (adjusted for inflation) is allowed for producers of nonconventional fuels. Qualified nonconventional fuels include oil produced from shale or tar sands; certain gas produced from geopressurized brine, Devonian shale, coal seams, a tight formation, or biomass; and synthetic fuels produced from coal (including lignite).

Blends of ethanol (from renewable sources) and gasoline ("gasohol") are exempt from a portion of the Federal motor fuels excise tax. This provision was first contained in the Energy Tax Act of 1978 and the exemption was increased in the Deficit Reduction Act of 1984 to 6 cents of the 9 cents per gallon Federal motor fuels excise tax. In addition, the Crude Oil Windfall Profits Tax Act of 1980 provided a credit of 40 cents per gallon for renewably derived ethanol used to produce a mixture of ethanol and gasoline. This credit was increased to 60 cents per gallon by the Deficit Reduction Act of 1984.

Several of the energy incentives contained in the Code are scheduled to expire in the near future. As noted above, each of the remaining business energy credits is scheduled to expire after September 30, 1990. The credit for producing fuel from a nonconventional source is applicable only for qualified fuels that are produced from a well drilled (or from a facility placed in service) before January 1, 1991, and which are sold before January 1, 2001. In addition, the alcohol fuels credit is scheduled to terminate with respect to any sale or use of such fuel after December 31, 1992.

U.S. policy has directly affected energy prices and production through non-tax means. For instance, Congress provided for the deregulation of natural gas prices in the Natural Gas Policy Act of 1978 and in the Natural Gas Wellhead Decontrol Act of 1989, and the Administration decontrolled petroleum prices between 1979 and 1981. As a result, domestic petroleum and natural gas prices are now at or near world market levels.

Primarily as a result of energy price increases and conservation measures, aggregate U.S. petroleum consumption decreased by over 10 percent from 1978 to 1989. During the same period, U.S. petroleum consumption per dollar of GNP decreased over 30 percent. Again using the same reference period, U.S. petroleum production (including natural gas plant liquids) decreased by approximately 10 percent.[5] The declines in both consumption and production have resulted in a reduction in net imports of crude oil and refined products of 11 percent from 1978 to 1989. However, over the 1978-1989 period, net petroleum imports first declined and then increased as a percentage of domestic supply. A recent rise in imports of oil has brought the U.S. dependence on imported oil to approximately the

[5] Figures calculated from U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 11, 115, 293.

I. OVERVIEW AND SUMMARY

A. Energy Tax Provisions in General

A significant portion of the nation's energy policy is located in the Internal Revenue Code rather than in Federal outlay and regulatory programs. Tax expenditures for energy in the Code, in the form of credits and other tax preferences, are estimated to be approximately $1 billion in fiscal year 1991, and are estimated to be approximately $7.5 billion over the five-year period of 1991 through 1995.[2] These figures compare to the total amount of budget authority for energy programs ($3.2 billion) requested by the Administration in the fiscal year 1991 budget.[3]

The Code contains provisions that influence both energy supply and energy conservation. The most significant of the energy supply provisions from the standpoint of tax revenue involve the deduction of expenses associated with the exploration, development, and depletion of fossil fuels (primarily oil, natural gas, and coal). These provisions became part of U.S. tax law soon after the adoption of the income tax.

Following the 1973 oil embargo, and the economic disruption associated with the subsequent quadrupling of the world price of oil, Congress enacted several tax credits in the Energy Tax Act of 1978 that were explicitly designed to reduce U.S. dependence on energy imports. These energy tax credits were designed to encourage private expenditures for energy conservation, investment in facilities for producing energy from renewable fuel sources, and for the production of nonconventional energy.[4] Since 1978, many of the energy credits enacted by Congress have been narrowed, repealed, or allowed to expire.

Following the Tax Reform Act of 1986 (the "1986 Act"), the only business energy tax credits that remained in effect were credits for certain investments in solar energy property, geothermal energy property, ocean thermal property, and biomass energy property. Although retained in the tax law, the 1986 Act reduced the credit percentage for most of these credits, and provided for the expira-

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[2] The figures are the arithmetic sum of individual tax expenditure items related to energy production as detailed in Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 1991-1995* (JCS-7-90), March 9, 1990. Each tax expenditure is measured in isolation and changes in more than one tax expenditure provision would be expected to produce interaction effects not captured in the sum of the individual tax expenditure items. Therefore, these estimates should be interpreted with caution. They are presented merely to provide information as to the magnitudes of tax subsidies for energy production relative to a truly comprehensive income tax system.

[3] This figure is the total for Budget Category 270, Energy, as reported in Office of Management and Budget, *Budget of the United States Government Fiscal Year 1991*, February 1990, p. A-146.

[4] In addition, the Crude Oil and Windfall Profits Tax Act of 1980 provided for the expensing of injectants used in tertiary oil recovery and allowed tax-exempt industrial development bonds to be used to finance certain alternative energy facilities.

same level it was in 1978 (41.3 percent for 1989 compared to 42.5 percent in 1978). In 1989, the Organization of Petroleum Exporting Countries ("OPEC") supplied 23.8 percent, and Arab members of OPEC supplied 12.3 percent, of U.S. petroleum demand.[6]

U.S. vulnerability to petroleum supply disruptions to some extent has been addressed by the establishment of a Federal strategic petroleum reserve ("SPR"). The SPR contains 580 million barrels of oil (as of year end 1989), capable of replacing 81 days of net oil imports at 1989 import rates (7.1 million barrels per day). Since 1985, the level of security provided by the SPR has declined yearly from 115 days of net oil imports in 1985 to 81 days of net oil imports in 1989. This decline reflects primarily the increased use of imported oil in the U.S., since the SPR has grown by approximately 86 million barrels over the period.

Each year from 1971 to 1982, the proved oil and gas reserves of the U.S. declined, meaning production outstripped net additions to reserves. However, the period 1982-1985 shows a rough equivalence between production and additions to proved reserves. Since 1986, though, annual domestic production of oil and gas has tended to be somewhat larger than additions to proved reserves (data for 1988 shows a slight reversal of this trend, with additions to proved reserves higher than production for that year). The decline in proved reserves of oil and gas can be partially attributed to a decline in exploration and development activity. For example, the total number of wells completed has declined from an annual average of over 80,000 wells for the 1982-1984 period to an annual average of 31,500 wells for 1987-1989.[7]

In evaluating the provisions of the Code affecting energy production and use, and proposed changes to these provisions, several important issues arise. First, the role of the U.S. Government needs to be addressed. For instance, a prominent question is whether the Federal Government, in view of national policy considerations, should attempt to influence the level and composition of private energy supply and demand, or whether it should let free-market prices determine these decisions. Second, the efficiency of using the tax system to affect energy production and utilization should be examined. Even if national energy policy seeks to encourage certain energy production and conservation activities, one needs to consider whether it is more efficient to use direct outlay programs or tax incentives to influence the use or production of energy. Third, the efficiency of present Code provisions should be analyzed to determine whether these provisions can be made more efficient. Fourth, the redistributional role of energy-related tax provisions should be weighed to determine the extent to which these provisions affect the distribution of income among individual taxpayers and between regions of the country.

B. Administration Proposals

President Bush's Fiscal Year 1991 Budget includes several proposed tax incentives for the domestic oil and gas industry. These

[6] U.S. Department of Energy, *Monthly Energy Review: February 1990* (May 1990), p. 13.
[7] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 97, 101, 103, 143.

proposals include: (1) a 5- and 10-percent tax credit for intangible drilling costs ("IDCs") attributable to exploratory drilling; (2) a 10-percent tax credit for capital expenditures on tertiary enhanced recovery projects; (3) increasing the net income limitation on percentage depletion from 50 to 100 percent of net income from the property; (4) allowing transferred proven property to qualify for percentage depletion; and (5) elimination of 80 percent of the minimum tax preference for intangible drilling costs attributable to exploratory drilling by independent producers. These proposals would be effective on January 1, 1991.

C. Senate Legislative Proposals

1. S. 41—Senator Nickles (Energy Security Act of 1989)

S. 41 would provide certain income tax incentives for domestic oil and gas production. The bill would allow percentage depletion at a 27.5-percent rate for domestic new, enhanced, and stripper production (from property held by an independent producer or royalty owner), increase the net income limitation on percentage depletion from 50 to 100 percent, increase the taxable income limitation on percentage depletion from 65 to 100 percent, and allow transferred proven properties to qualify for percentage depletion.

The bill also would treat geological and geophysical ("G&G") costs as expensible similar to the present-law treatment of IDCs, and would exclude IDCs from the list of preference items for purposes of the alternative minimum tax. The bill would provide a 5- and 10-percent crude oil and natural gas exploration and development tax credit. Further, the bill would apply a 3-year statute of limitations on crude oil windfall profit tax assessments in certain cases of underwithholding of tax where the producer did not file a required tax return.

The provisions generally would become effective on the date of enactment.

2. S. 42—Senator Nickles (Domestic Petroleum Security Act of 1989)

S. 42 would impose an excise tax on crude oil or any other refined petroleum product that is imported into the United States. With respect to crude oil, the rate of the tax would be the excess (if any) of $18 over the price per barrel as established by the Secretary of the Treasury.[8] For other refined petroleum products, the excise tax rate would be equal to $3 plus the tax rate determined for crude oil. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

The bill would be effective with respect to sales or use of imported crude oil or refined petroleum products on or after date of enactment.

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[8] This price, which is to be determined on a weekly basis under the bill, is the weighted average international price of a barrel of crude oil for the preceding four weeks.

3. S. 161—Senators Boren and Kassebaum

S. 161 would impose an excise tax on any petroleum product that is imported into the United States if the average international price of crude oil for any 4-week period is less than $18, and the product is entered into the United States for use, consumption, or warehousing during the week following such 4-week period. The rate of the tax would be the excess of $18 over the average international price per barrel of crude oil for the preceding 4-week period. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

The bill would be effective with respect to sales of imported petroleum products in calendar quarters beginning more than 30 days after date of enactment.

4. S. 234—Senator Boren (Energy Security Incentive Act of 1989)

S. 234 would provide certain income tax incentives for domestic oil and gas production. Among these, the bill would increase the percentage depletion rate if the taxpayer's average removal price for crude oil is less than $20 per barrel, repeal the 50 percent of net income limitation and 65 percent of taxable income limitation on percentage depletion, allow transferred proven properties to qualify for percentage depletion, and provide for a carryover of depletion deductions in excess of basis.

In addition, the bill would eliminate the minimum tax preference for IDCs, eliminate the requirement that integrated oil companies capitalize 30 percent of their IDCs, eliminate recapture of IDCs and depletion upon disposition of an oil, gas or geothermal property, and treat G&G costs and surface casing costs as expensible in a manner similar to the treatment presently provided for IDCs.

The bill also would provide a 10-percent tax credit for maintaining economically marginal wells, and provide a 10- and 20-percent tax credit for crude oil and natural gas exploration and development costs. Further, the bill would extend the credit for producing fuel from nonconventional sources for five years (until 1996), and expand it to cover certain tight sands gas.

The provisions generally would be effective on the date of enactment.

5. S. 343—Senators Bingaman and Boren

S. 343 would extend the placed in service expiration date for the nonconventional fuels credit for 10 years. Thus, the credit would apply with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 2001. In addition, the bill would extend for 10 years the expiration date of the nonconventional fuels credit for sales of qualified fuels. Under the bill, the credit would apply to sales of qualified fuels occurring before January 1, 2011.

The bill also generally would extend the credit to all gas produced from a tight formation.

6. S. 425—Senator Domenici (Tight Formations Tax Credit Restoration Act of 1989)

S. 425 generally would treat gas produced from a tight formation as qualifying for the nonconventional fuels production credit. This provision would be effective for taxable years beginning after December 31, 1984.[9] The bill also would permit the credit to offset both the regular tax and the alternative minimum tax. This section of the bill would be effective for taxable years beginning after December 31, 1986.

7. S. 449—Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson (Domestic Energy Security Act of 1989)

S. 449 includes various energy tax incentive provisions, including provisions that would permit the expensing of G&G costs attributable to domestic oil and gas property, and allow for early accrual of expenses related to the removal of offshore oil and gas production facilities if a liability for such removal is included in the terms of an offshore oil or gas lease. The bill also contains a number of provisions that would amend the percentage depletion rules. For example, the bill would increase the 50-percent net income limitation to 100 percent, repeal the 65-percent taxable income limitation, and repeal the limitation on claiming percentage depletion on transferred proven oil and gas property.

The bill would repeal the requirement that integrated oil companies capitalize 30 percent of their otherwise deductible IDCs. With respect to the alternative minimum tax, the bill would eliminate the tax preference items related to IDCs and excess percentage depletion.

The bill also would provide for a 20-percent domestic exploration and development tax credit and a 20-percent tertiary recovery tax credit. Each of these credits would be permitted to fully offset both the regular tax and the alternative minimum tax. In addition, the bill would extend the expiration date of the nonconventional fuels production credit to December 31, 1998, and would make certain tight sands gas eligible for that credit.

Further, the bill contains provisions that would exclude oil and gas exploration and development costs from the uniform capitalization rules, and would repeal the treatment prescribed in Revenue Ruling 77-176 with respect to certain mineral sharing arrangements.

The provisions generally would be effective as of the date of enactment.

8. S. 828—Senators Domenici, Boren, Dole, Nickles, Garn, Wallop, Bingaman, Johnston, McClure, and Gramm (Enhanced Oil and Gas Recovery Tax Act of 1989)

S. 828 would increase the percentage depletion rate for domestic oil and gas recovered through enhanced recovery techniques to 27.5 percent, phased down as the price of crude oil increases above $30

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[9] If on the date of enactment any refund or credit of tax resulting from this legislation would be barred by the statute of limitations, such refund or credit would, nevertheless, be made or allowed if a claim is filed within one year of the date of enactment.

per barrel adjusted for inflation. The bill also would increase the net income limitation on percentage depletion of this oil and gas to 100 percent. The alternative minimum tax preferences for percentage depletion and intangible drilling costs would not apply to the deductions attributable to this oil and gas. Further, a 10-percent research and development credit would apply to research to discover or improve tertiary recovery methods.

The provisions generally would be effective beginning on the date of enactment and would expire on January 1, 2010.

9. S. 850—Senators Johnston and Bingaman (Energy Security Tax Act)

S. 850 would impose an excise tax on any crude oil, refined petroleum product, or petrochemical feedstock or derivative that is imported into the United States. With respect to crude oil, the rate of the tax would be the excess (if any) of $24 per barrel over the most recently published average price per barrel of internationally traded oil. For refined petroleum products and petrochemical feedstocks or derivatives, the excise tax rate would be equal to the excess (if any) of $26.50 per barrel (or barrel equivalent) over the most recently published average price per barrel of internationally traded oil. The bill would be effective with respect to sales or use of imported crude oil, refined petroleum products, or petrochemical feedstocks or derivatives on or after the date of enactment.

10. S. 914—Senator Matsunaga

S. 914 would extend through December 31, 1994, the current business energy credits for solar energy property, geothermal property, and ocean thermal property.

11. S. 1565—Senators Dole, Domenici, Boren, Nickles, Wallop, Gramm, and Baucus (Marginal Energy Producers Incentives Act of 1989)

S. 1565 contains five provisions, three of which are applicable only to "marginal" oil and gas production. For this purpose, marginal production includes production from stripper wells and production of heavy oil.

Under the bill, the limitation on claiming percentage depletion on transferred proven properties would be repealed, and the 50-percent net income limitation on percentage depletion would be changed to a 100-percent limitation. With respect only to marginal production, the bill would permit percentage depletion to be claimed by independent producers and royalty owners without taking into account the 1,000 barrel-per-day limitation. In addition, percentage depletion with respect to such production would not be subject to the 65-percent taxable income limitation. Further, excess percentage depletion on marginal properties would not constitute an item of tax preference for the alternative minimum tax.

The bill's provisions would be effective for taxable years ending after date of enactment.

12. S. 2025—Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, and Hollings

S. 2025 would provide for the permanent extension of various tax provisions that are currently scheduled to expire. Among these, the bill would extend permanently the current business energy credits for ocean thermal property, solar energy property, and geothermal property. In addition, the bill would provide for the permanent extension of the nonconventional fuels production credit.

13. S. 2288—Senators Domenici, Boren, Johnston, Dole, Bingaman, Ford, Simpson, Wallop, and Burns (Nonconventional Fuels Production Incentives Act of 1990)

S. 2288 would extend the nonconventional fuels production credit by two years, making it applicable with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 1993. In addition, the bill would extend the credit to the production of gas from a tight formation if that gas is (1) produced from a well drilled after May 12, 1990, or (2) produced from a well drilled before May 12, 1990, but only if on that date gas produced from that well was gas that was regulated by the United States as to its price, and for which the maximum lawful price applicable under the Natural Gas Policy Act of 1978 is at least 150 percent of the then applicable price under section 103 of that Act. This latter provision would apply to gas produced after May 12, 1990.

II. DESCRIPTION OF TAX PROVISIONS AND PROPOSALS

A. Tax Provisions Relating To Oil And Gas Production

1. Intangible Drilling and Development Costs

Present Law and Background

General rules

Costs incurred by an operator to develop an oil or gas property for production are of two types: (1) intangible drilling and development costs ("IDCs"), and (2) depreciable costs.

Under present law, IDCs generally may either be currently expensed or else may be capitalized and recovered through depletion or depreciation deductions (as appropriate), at the election of the operator (Code sec. 263(c)).[10] In general, IDCs include expenditures by the property operator incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas (or geothermal energy) which are neither for the purchase of tangible property nor part of the acquisition price of an interest in the property.[11] IDCs include amounts paid for labor, fuel, repairs, hauling, supplies, etc., to clear and drain the well site, make an access road, and do such survey and geological work as is necessary to prepare for actual drilling. They also include charges for labor, etc., necessary to construct derricks, tanks, pipelines, and other physical structures necessary to drill the wells and prepare them for production. IDCs may include amounts paid or accrued to drill, shoot, and clean the wells. IDCs also include amounts paid or accrued by the property operator for drilling or development work done by contractors under any form of contract.

Depreciable costs are amounts paid or accrued during the development of a property to acquire tangible property ordinarily considered to have a salvage value. For example, the costs of drilling tools, pipe, cases, tubing, engines, boilers, machines, etc., fall into this category. This class of expenditures also includes certain amounts paid or accrued for wages, fuel, repairs, etc., in connection with equipment or facilities not incidental or necessary for the drilling of wells, such as structures to store or treat oil or natural gas. These expenditures must be capitalized and depreciated in the same manner as ordinary items of equipment, and they are treated the same for both independent and integrated producers.

Only persons holding an operating interest in a property are entitled to deduct IDCs. This includes an operating or working interest in any tract or parcel of oil- or gas-producing land either as a

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[10] As discussed more fully below, a third alternative permits taxpayers to elect to amortize certain IDCs over a 60-month period.

[11] The acquisition price for the actual oil- or gas-producing property, together with certain other costs, is recovered through depletion deductions (see discussion of depletion below).

fee owner, or under a lease or any other form of contract granting working or operating rights. In general, the operating interest in an oil or gas property must bear the cost of developing and operating the property. The term operating interest does not include royalty interests or similar interests such as production payment rights or net profits interests.

In the case of IDCs paid or incurred with respect to an oil, gas, or geothermal well located outside of the United States, the option to expense such costs is not available. Instead, such costs are (at the election of the taxpayer) either included in the property's basis for purposes of claiming depletion, or capitalized and amortized ratably over the 10-taxable year period beginning with the taxable year during which the costs were paid or incurred.

Generally, if IDCs are not expensed, but are capitalized, they can be recovered through depletion or depreciation, as appropriate. However, if IDCs are capitalized and are paid or incurred with respect to a nonproductive well ("dry hole"), they may be deducted, at the election of the operator, as an ordinary loss in the taxable year in which the dry hole is completed. Thus, a taxpayer has the option of capitalizing IDCs for productive wells while expensing those relating to dry holes.

Thirty percent reduction for integrated producers

In the case of a corporation which is not an independent producer [12] (i.e., which is an "integrated" producer), the allowable deduction with respect to IDCs is reduced by 30 percent. The disallowed amount must be capitalized and amortized over a 60-month period, starting with the month in which the costs are paid or accrued. (These capitalized IDCs are not taken into account for purposes of determining cost depletion.) Amounts paid or accrued with respect to non-productive wells (dry hole costs) remain fully deductible when the non-productive well is completed.

Recapture of IDCs

If an operator elects to expense IDCs and later disposes of an oil, gas, or geothermal property, a portion of the gain recognized (if any) as a result of the disposition of that property must be characterized as ordinary income (instead of capital gain) (sec. 1254(a)). The portion so characterized is equal to the lesser of (1) the amount of IDCs deducted with respect to that property which, but for being deducted, would have been reflected in the adjusted basis of the property plus the deductions for depletion which reduced the adjusted basis of that property, or (2) the gain on the sale, exchange, or involuntary conversion of the property.[13]

Alternative minimum tax

While IDCs are currently deductible (at the election of the operator), the economic value of this current deduction may be reduced by the effect of the alternative minimum tax with respect to both

[12] This term is defined in the same manner as it is for purposes of percentage depletion (discussed below).

[13] Even if the taxpayer did not elect to expense IDCs, ordinary income recapture of depletion deductions with respect to the property disposed of would be required.

corporate and noncorporate operators. In the case of an individual, trust, or estate (i.e., a noncorporate taxpayer), the alternative minimum tax is equal to 21 percent of the excess of the taxpayer's alternative minimum taxable income over a statutory exemption amount, reduced by the alternative minimum tax foreign tax credit. In the case of a corporate taxpayer, the alternative minimum tax is equal to 20 percent of such excess.[14] Alternative minimum taxable income is taxable income, determined with respect to certain adjustments (as specified in secs. 56 and 58), plus the amount of the taxpayer's tax preference items (as specified in sec. 57).

In general, IDC deductions on successful wells are a tax preference item for purposes of the alternative minimum tax to the extent they exceed the amount which would have been deductible in that year had the IDCs been capitalized and recovered over a 120-month, straight-line amortization period (i.e., "excess IDCs"), but only to the extent that the excess IDCs are greater than 65 percent of the taxpayer's income for the taxable year from the oil or gas property (sec. 57(a)(2)). The 120-month amortization period applies on a well by well basis, starting with the month in which production for the well begins. At the election of the operator, the cost depletion method may be substituted for the 120-month amortization in determining the amount of tax preference. Generally, a minimum tax credit is allowed in succeeding years for minimum tax paid by reason of the preference for IDCs.

In the case of corporations, one adjustment that is required in arriving at alternative minimum taxable income is an adjustment based on adjusted current earnings (the "ACE adjustment") (sec. 56(g)). Under the ACE adjustment, a corporation's alternative minimum taxable income for a taxable year is increased by 75 percent of the excess (if any) of the corporation's adjusted current earnings computed in a manner similar to earnings and profits, over its alternative minimum taxable income (determined without regard to the ACE adjustment or any net operating loss deduction). For the purpose of determining adjusted current earnings, IDCs deducted for regular tax purposes are required to be capitalized and amortized over a 60-month period beginning with the month during which the IDC was paid or incurred.

Under a special rule provided in section 59(e), a taxpayer is permitted to elect to capitalize any amount of otherwise deductible IDCs and amortize that amount over a 60-month period beginning with the month in which the IDC was paid or incurred. Prior to the 1989 Act, the amortization period for IDCs with respect to which this special election was made was 120 months, beginning with the taxable year in which the IDC was paid or incurred. This special rule is applicable for both regular tax and alternative minimum tax purposes.

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[14] The exemption amount generally is equal to $30,000 for single individuals, $40,000 for corporations, married couples filing joint returns, or surviving spouses, and $20,000 for married persons filing separate returns or for estates or trusts (sec. 55(d)). These exemption amounts, however, are phased out for certain high-income taxpayers.

Administration Proposal

The Administration proposal would eliminate 80 percent of the current alternative minimum tax preference generated by exploratory IDCs incurred by an independent producer.[15] The proposal would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would repeal the treatment of excess IDCs as a minimum tax preference item, effective for costs paid or incurred after the date of enactment.

S. 234 (Senator Boren)

S. 234 would repeal the rules providing for recapture of intangible drilling cost deductions and depletion deductions upon disposition of an oil, gas or geothermal property. This provision would be effective for dispositions of oil, gas, or geothermal properties after the date of enactment.

The bill also would repeal the treatment of excess IDCs as a minimum tax preference. In addition, the bill would repeal the present-law requirement that integrated oil companies capitalize 30 percent of their IDCs. These proposals would be effective for costs paid or incurred after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would repeal the treatment of excess IDCs as a minimum tax preference. The bill also would repeal the present-law requirement that integrated oil companies capitalize 30 percent of their IDCs. These proposals would be effective for costs paid or incurred after date of enactment.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would repeal the treatment of excess IDCs as a minimum tax preference for oil and gas removed through enhanced recovery techniques if the removal price of oil is less than $30 per barrel adjusted for inflation.[16] This provision would be effective for costs paid or incurred after date of enactment, and before January 1, 2010 (with respect to projects beginning before January 1, 2000).

Analysis

In general

When considering whether energy incentives should be included as part of the tax law, one issue to be considered is whether investments in oil and gas should be given preferential treatment relative to other capital investments. The Administration contends that preferential treatment of IDCs is necessary to increase the

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[15] The Administration proposal does not discuss the treatment of IDCs under the present-law ACE adjustment.

[16] See discussion of oil and gas recovered through enhanced recovery techniques below.

level of domestic exploratory drilling (and ultimately domestic oil and gas reserves), thus reducing the United States' dependence on foreign oil supplies and improving U.S. energy security.

Evidence that domestic drilling activity has fallen over recent years is dramatic. According to Department of Energy statistics, the number of exploratory and development oil and gas wells drilled in 1989 (28,470) was smaller than the number drilled in any year since 1973 (when the number of wells drilled was 27,690).[17] The number of seismic crews and rotary rigs in use has also decreased significantly in recent years. Both the number of seismic crews and the number of rotary rigs in operation were smaller in 1989 than in any year since 1949. Part of this may reflect increased productivity on the part of drilling firms (in that fewer crews are needed to drill the same number of wells). However, a large portion of the decline reflects decreased domestic drilling activity.

The various proposals are premised on the contention that providing tax incentives for drilling activity is necessary to increase U.S. energy security. In 1989, the U.S. imported an average of 8.0 million barrels of oil per day, accounting for 41.3 percent of domestic petroleum supply. In the event of a complete curtailment of imports, the SPR could, at current levels, replace net imports for approximately 81 days. If the SPR were depleted, domestic production would have to nearly double to replace imports (assuming that domestic consumption does not decline). As of 1988, proved reserves of crude oil amounted to just 9.0 years of domestic production (at 1988 rate of 8.1 million barrels per day). If production rates were increased to replace all imports, proved reserves would be exhausted in less than 4.5 years.[17A] To respond to a future oil import curtailment, it is argued that proved reserves must be increased now because it can take several years from initial discovery for a petroleum reservoir to reach maximum production. It is argued that energy security would be increased by expanding tax preferences in current law for intangible drilling costs and percentage depletion. It is also argued that these tax incentives should be expanded in order to maintain adequate levels of labor and equipment in the oil and gas industry in the event of an energy crisis.

Some have questioned this view on the grounds that drilling incentives may lead to a substitution of domestic oil for imports—in effect "draining America first". They argue that domestic oil production is likely to rise along with reserve additions yielding little net increase in field reserves. Some argue that it may be more efficient to stockpile petroleum by filling the SPR with oil purchased in the world market at the currently prevailing prices than to provide additional incentives for domestic production.

Others argue that the object of energy policy should be complete energy independence. In this view, tax incentives for oil and gas exploration serve energy policy by increasing domestic production and replacing imports. These incentives might also improve the merchandise trade balance since net petroleum imports accounted

[17] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), p. 97 (excludes service well, stratigraphic tests, and core tests). The oil and gas well footage drilled in 1989 (130.9 million feet) was the smallest for any year since 1949 except for 1971 (when the footage drilled was 127.3 million feet).

[17A] U.S. Department of Energy, *Annual Energy Review 1989* (May 1990), pp. 103, 115.

for over 10 percent of all imports in 1989.[18] However, enhanced energy self-sufficiency might be achieved more efficiently by a tax on imported oil. Such a tax, it is argued, would encourage conservation and fuel switching, as well as production, by raising the price of domestic oil. Opponents of an oil import fee might contend that the price increase of domestic oil would, in effect, be a wealth transfer to owners of oil reserves, since this would provide an unexpected boost to the market value of these reserves. In addition, an oil import fee might raise questions regarding U.S. trade policy in the context of the General Agreement on Tariffs and Trade (GATT).

From an accounting standpoint, part of the reason that IDCs have historically been allowed to be expensed [19] (aside from the implicit tax subsidy) is the difficulty of establishing an alternate recovery period, because the "useful life" of a well may not be known in advance and its production may occur at an uneven rate. (This is similar to the problem faced in determining a proper oil and gas depletion method.)

Recapture of IDCs

Gain from the sale of oil, gas, and geothermal property attributable to deductions for intangible drilling costs and depletion allowances are treated as ordinary income rather than capital gain. Since ordinary income and capital gains are taxed at the same rate, the effect of the recapture rule is to prevent recapture income from being sheltered by capital losses for taxpayers with net capital losses (or capital loss carryforwards). The recapture rules for oil and gas property are similar to the rules applicable to depreciable property. The relevant provision of S. 234 would afford oil and gas property more favorable recapture treatment than depreciable property—treatment that actually would be more beneficial to the taxpayer than the rules in existence before the 1986 Act.[20]

Alternative minimum tax

The alternative minimum tax, as amended by the 1986 Act, requires that taxpayers pay a minimum rate of tax (21 percent in the case of noncorporate taxpayers and 20 percent in the case of corporations) on a broad measure of their economic income. To the extent that taxable income is reduced by reason of the expensing of IDCs on successful wells, the 65-percent income offset contained in present law lowers the 20- and 21-percent effective rates of tax. Repeal of the tax preference for excess IDCs would allow some producers to further reduce (or eliminate) their effective rate of tax.

An argument in favor of such a proposal is that it would increase the tax incentive for incurring drilling expenses for producers that are subject to the alternative minimum tax. To the extent that repeal of the IDC preference allows producers to shelter most or all

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[18] U.S. Department of Energy, *Monthly Energy Review: February 1990* (May 1990), p. 11.

[19] The option to expense IDCs has been permitted by regulations since the Revenue Act of 1918. In 1945, in response to a case casting doubt on this treatment, Congress passed a concurrent resolution which specifically approved the Treasury regulations granting the option to expense IDCs. The Internal Revenue Code of 1954 (sec. 263(c)) directs the Treasury Department to promulgate regulations allowing for the option to expense IDCs.

[20] Prior to the 1986 Act, recapture generally was required only for IDCs.

of their income from tax, however, other taxpayers may view the tax law as inequitable. Also, allowing an exception to the alternative minimum tax for the oil and gas industry might be a precedent for other industries seeking exceptions from the minimum tax.

2. Percentage Depletion

Present Law and Background

General rules

Depletion, like depreciation, is a class of ordinary and necessary business expense. In both cases, the taxpayer is allowed a deduction in recognition of the fact that an asset—in the case of depletion, the oil or gas reserve itself—is being expended in order to produce income. Certain costs incurred prior to drilling an oil- or gas-producing property are recovered through the depletion deduction. These include costs of acquiring the lease or other interest in the property, and geological and geophysical costs (in advance of actual drilling). Depletion is available to any person having an economic interest in a producing property (including royalty interests).

Two methods of depletion are currently allowable under the Internal Revenue Code: (1) the cost depletion method, and (2) the percentage depletion method. Under the cost depletion method, the taxpayer deducts that portion of the adjusted basis of the property which is equal to the ratio of units sold from that property during the taxable year to the number of units remaining as of the taxable year (in general, the number of units remaining to be recovered in the property at the end of the taxable year, plus the number of units sold during the taxable year). The amount recovered under cost depletion thus may not exceed the taxpayer's basis in the property.

Under percentage depletion, 15 percent of the taxpayer's gross income from an oil- or gas-producing property is allowed as a deduction in each taxable year (sec. 613A(c)). The amount deducted may not exceed 50 percent of the net income from that property in any year (the "net income limitation"). Additionally, the deduction for all oil and gas properties may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).[21] Because percentage depletion is computed without regard to the taxpayer's basis in a property, cumulative depletion deductions may be greater than the amount expended by the taxpayer to acquire or develop the property.

A taxpayer is required to determine its depletion deduction for each oil and gas property under both the percentage depletion method (if the taxpayer is entitled to use this method) and the cost depletion method. If the cost depletion deduction is larger, the taxpayer must utilize that method for the taxable year in question.

Similar rules apply to geothermal deposits located in the United States, except that the 65 percent of taxable income limitation does not apply.

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[21] Amounts disallowed as a result of this rule may be carried forward into later taxable years.

Limitation on percentage depletion or oil and gas to independent producers and royalty owners

The Tax Reduction Act of 1975 repealed percentage depletion with respect to much oil and gas production. Under that Act, independent producers and royalty owners (as contrasted to integrated oil companies) are allowed to claim percentage depletion with respect to up to 1,000 barrels of average daily production of domestic crude oil or an equivalent amount of domestic natural gas.[22] For producers of both oil and natural gas, this limitation applies on a combined basis.

For purposes of percentage depletion, an independent producer is any producer who is not a "retailer" or "refiner." A retailer is any person who directly, or through a related person, sells oil or natural gas or any product derived therefrom (1) through any retail outlet operated by the taxpayer or related person, or (2) to any person that is obligated to market or distribute such oil or natural gas (or product derived therefrom) under the name of the taxpayer or the related person, or that has the authority to occupy any retail outlet owned by the taxpayer or a related person (sec. 613A(d)(2)). Bulk sales to commercial or industrial users, and bulk sales of aviation fuel to the Department of Defense, are excluded for this purpose. Further, a person is not a retailer within the meaning of this provision if the combined gross receipts of that person and all related persons from the retail sale of oil, natural gas, or any product derived therefrom do not exceed $5 million for the taxable year.

A refiner is any person who directly or through a related person engages in the refining of crude oil, but only if such taxpayer or related person has a refinery run in excess of 50,000 barrels per day on any day during the taxable year (sec. 613A(d)(4)).

In addition to the independent producer and royalty owner exception, certain sales of natural gas under a fixed contract in effect on February 1, 1975, and certain natural gas from geopressurized brine,[23] are eligible for percentage depletion, at rates of 22 percent and 10 percent respectively. These exceptions apply without regard to the 1,000 barrel per day limitation and regardless of whether the producer is an independent producer or an integrated oil company.

To prevent proliferation of the independent producer exception, all production owned by businesses under common control and members of the same family must be aggregated. Each group is then treated as one producer for application of the 1,000-barrel amount. Further, if an interest in a proven oil or gas property is transferred (subject to certain exceptions), the production from such interest does not qualify for percentage depletion. The exceptions to this rule include transfers at death, certain transfers to controlled corporations, and transfers between controlled corporations or other business entities.

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[22] As originally enacted, the depletable oil quantity was 2,000 barrels of average daily production. This was gradually phased down to 1,000 barrels of average daily production for 1980 and thereafter. The 1975 Act also phased down the percentage depletion rate from 22 percent in 1975 to 15 percent in 1984 and thereafter.

[23] This exception is limited to wells the drilling of which began between September 30, 1978, and January 1, 1984.

Alternative minimum tax

The excess of percentage depletion over the taxpayer's adjusted basis for each oil or gas property, [24] for any taxable year, is treated as a preference item for purposes of the alternative minimum tax.[25]

Administration Proposal

The Administration proposal would increase the oil and gas percentage depletion net income limitation from 50 percent to 100 percent of net income from the property. In addition, the proposal would repeal the rule which prevents percentage depletion from being claimed on transferred proven properties. The proposals would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would provide a 27.5-percent depletion rate with respect to a taxpayer's domestic new, enhanced, or stripper production, as defined under the bill. This deduction would be available to all taxpayers (including independent and integrated producers), for an unlimited amount of production. For purposes of the bill, new production would include production from any property that commences production after March 31, 1987. Enhanced production would include (1) the increase in average daily production for the taxable year over average daily production for the period January 1, 1987, through March 31, 1987, and (2) incremental tertiary oil as defined for prior law windfall profit tax purposes (sec. 4993(a)). Stripper production would include production from any stripper well property as defined in the June 1979 Department of Energy regulations. This provision would be effective for production during the taxpayer's first full taxable quarter following the date of enactment.

In addition, S. 41 would repeal the percentage depletion antitransfer provision, effective for transfers of property taking place after the date of enactment. It also would increase the net income limitation from 50 to 100 percent and increase the taxable income limitation from 65 percent to 100 percent, effective for production for taxable years beginning after the date of enactment.

S. 234 (Senator Boren)

S. 234 would increase the percentage depletion rate for crude oil and natural gas, if the taxpayer's average removal price for oil and gas sold during the calendar year is $20 per barrel or less. The amount of the increase would depend upon the average annual removal price, as shown in the following table:

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[24] In general, the term "property", for depletion purposes, means each separate interest owned by the taxpayer in each separate tract or parcel of land. In the case of oil and gas wells and geothermal deposits, all of a taxpayer's operating interests in each separate tract or parcel of land are generally treated as one property, subject to an election to separate certain interests in the same tract or panel.

[25] For a more in depth discussion of the alternative minimum tax, see above.

*If the average annual removal price during the calendar year is:**	*The applicable percentage is:*
Less than $10	30 percent
$10 to $15	25 percent
$15 to $20	20 percent
Greater than $20	15 percent

*These prices are measured in dollars per barrel.

The "average annual removal price" for the taxpayer would be determined by dividing the taxpayer's aggregate production of domestic crude oil or natural gas for the calendar year by the aggregate amount for which such production was sold.[26] In the case of crude oil or natural gas sold between related persons, removed before sale, or refined on the production premises, a constructive sales price would be used. For example, if a taxpayer sold 100,000 barrels of crude oil for an aggregate price of $1.8 million in calendar year 1990, the taxpayer's average removal price would be $18 per barrel, and a percentage depletion rate of 20 percent would apply to all production by that taxpayer in 1990.

Percentage depletion would continue to be limited to 1,000 barrels per day of domestic crude oil production (or an equivalent amount of natural gas) by independent producers. Additionally, the limitation on percentage depletion deductions for all oil and gas properties to 65 percent of the taxpayer's overall taxable income would remain in effect.

The changes in the percentage depletion rate would be effective for production during calendar years beginning after date of enactment.

The bill also would repeal the percentage depletion anti-transfer provision, for production during calendar years beginning after date of enactment. In addition, it would repeal the 50-percent net income limitation on percentage depletion deductions for oil and gas properties. Thus, percentage depletion would equal the specified percentage of gross income from each property, without regard to the net income from that property. The overall limitation to 65 percent of adjusted taxable income would continue to apply. The repeal of the net income limitation would be effective for taxable years beginning after the date of enactment.

Finally, the bill would allow a taxpayer to elect to treat any amount of percentage depletion in excess of basis as a deduction for the next succeeding year rather than the current year.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would repeal the percentage depletion anti-transfer provision, for transfers occurring after date of enactment. It also would repeal the 50-percent net income limitation on percentage depletion deductions for oil and gas properties. The bill also would repeal the 65-percent taxable income limitation on oil and gas per-

[26] The bill apparently intends that the average annual removal price be determined by dividing removal production in barrel-of-oil equivalents into (rather than by) the amount for which such production was sold

centage depletion. Thus, percentage depletion would equal the specified percentage of gross income from each property, without regard to either the net income from that property or the taxpayer's taxable income. These latter two provisions would apply to taxable years ending after date of enactment.

In addition, the bill would eliminate percentage depletion in excess of basis as an item of tax preference for the alternative minimum tax.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would provide a 27.5-percent depletion rate with respect to the production of domestic incremental tertiary crude oil and gas during the enhanced recovery period. This deduction would be available to all taxpayers (including independent and integrated producers) for an unlimited amount of production. The 27.5-percent rate would be phased-down to 15 percent by one percentage point for every dollar that the taxpayer's average removal price of oil for the calendar year exceeds $30 dollars per barrel adjusted for post-1989 inflation.

For purposes of the bill, incremental tertiary oil and gas includes incremental tertiary oil as defined for prior law windfall profit tax purposes (sec. 4993(a) using the current Department of Energy (DOE) regulations). Tertiary recovery techniques, under DOE regulations, include miscible fluid displacement, steam driven injection, microemulsion or micellar emulsion flooding, in situ combustion, polymer augmented flooding, cyclic steam injection, alkaline or caustic flooding, carbon dioxide augmented water flooding, and immiscible carbon dioxide displacement. Reservoir improvements (including infill patterns and pattern conformance) incident to a qualified tertiary recovery project would be treated as a project which is otherwise a qualified tertiary project. Oil and gas produced from nonhydrocarbon gas flooding, tight formation gas, and certain tight formation oil would also qualify as incremental tertiary oil and gas under the bill.

The enhanced recovery period is a period, as determined by a schedule to be published by the Secretary of the Treasury, based on the average period for a project to recover the expenses of the type of project involved for that region. The recovery period would not end earlier than six months after the publication of the schedule by the Secretary.

The provision would be effective for production after the date of enactment and before January 1, 2010. It would apply after December 31, 1999, only to production from a project begun before January 1, 2000. Expansion of a project begun on or after date of enactment would be treated as a separate project. In the case of production from a project begun on or before the date of enactment, the percentage rate would be 18 percent rather than 27.5 percent.

With respect to production after the date of enactment, the bill would increase the net income limitation from 50 to 100 percent for incremental tertiary oil and gas to which the increased percentage depletion rate under the bill applies.

Also, the bill would remove from treatment as a minimum tax preference item excess depletion on incremental tertiary oil or gas properties if the average annual removal price for the calendar year in which the taxable year begins is less than $30 (adjusted for inflation). This provision would be effective for production after date of enactment, and before January 1, 2010 (with respect to projects beginning before January 1, 2000).

S. 1565 (Senators Dole, Domenici, Boren, Nickles, Wallop, Gramm, and Baucus)

S. 1565 contains several provisions related to oil and gas percentage depletion for independent producers and royalty owners. First, the bill would repeal the anti-transfer limitation with respect to oil and gas property that is transferred after the date of enactment. It also would replace the 50-percent net income limitation with a 100-percent net income limitation. This latter provision would be effective for taxable years ending after date of enactment.

The following three provisions of S. 1565 would be applicable only with respect to marginal production of oil and gas. The bill defines marginal production as domestic crude oil or natural gas produced from a stripper well,[27] or domestic crude oil which is heavy oil. Each of these provisions would be effective for taxable years ending after the date of enactment.

First, with respect to such marginal production, percentage depletion would be permitted to be claimed without a 1,000 barrel per day limitation. Second, the bill would repeal the 65-percent taxable income limitation with respect to marginal production. Third, excess percentage depletion attributable to marginal production would not constitute an item of tax preference for the alternative minimum tax.

1989 Senate Finance Committee Provision

The 1989 budget reconciliation provisions as approved by the Senate Finance Committee (included in S. 1750 as reported by the Senate Budget Committee) would have repealed the 50-percent net income limitation for certain marginal production of domestic crude oil and natural gas. Production qualifying as marginal under the provision included oil or gas produced from a stripper well, and heavy oil. This provision was removed from the bill by Senate floor amendment.

Analysis

In general

Under percentage depletion, producers are allowed a deduction for a set percentage of gross income from a given property in each year (15 percent, in the case of independent oil and gas producers and royalty owners). Under present law, this allowance may reduce the net (i.e., taxable) income from a property by up to 50 percent in each year. Although nominally a form of cost recovery, percentage depletion has come to be seen as an implicit tax subsidy to the oil

[27] The bill defines stripper well differently than does the 1979 Department of Energy regulations. Under the bill, a stripper well generally is any well that produced an average of 15-or-less barrels (or barrel equivalents) per day over any 6-month period (3 months in the case of a gas well) beginning after December 31, 1985.

and gas industry, in order to encourage production, because the total deductions with respect to a property may substantially exceed the actual costs invested in the property.[28] Since the Tax Reduction Act of 1975, this incentive has been limited to specified amounts of production by independent producers and royalty owners.

The various proposals regarding percentage depletion, by reducing the tax rate on oil and gas income, might favor the oil and gas industry over other sectors of the economy, such as agriculture and manufacturing. This might impact the long-run overall competitiveness of the U.S. economy. In addition, since oil and gas reserves are a finite resource, some may argue that encouraging production now would reduce domestic supplies in the future.

Percentage depletion rate

Under S. 234, the rate of percentage depletion for oil and gas would be increased from 15 percent to 30 percent as the average annual removal price of oil falls from $20 to $10 per barrel. The effect would be to increase the rate of percentage depletion when the income of domestic producers falls due to declining world oil prices. Other proposals (S. 41, and S. 828) also would increase the percentage depletion rate under specified circumstances.

An argument in favor of a variable rate of percentage depletion is that it would tend to stabilize the income of oil and gas producers. This provision is similar to certain agriculture stabilization programs which increase payments to farmers when farm income falls as a result of oversupply. However, such a policy could tend to destabilize the world petroleum market by encouraging domestic production when the world market is confronted by a glut (as evidenced by low prices). This could make it more difficult for the major oil-importing countries to coordinate energy policies.

Increasing the percentage depletion deduction for incremental tertiary oil and gas would provide a tax incentive to recover oil and gas which may not be recovered if the oil and gas were taxed under present law. However, to the extent that the recovery is not profitable from an economic viewpoint, lowering the tax on the profits may not provide relief.

Increasing the rate of percentage depletion would provide little or no benefit to many of the oil and gas producers hardest hit by the current relatively low petroleum prices: those producers with net operating losses. Additional depletion deductions have no immediate value to producers without income tax liability. Increasing the rate of percentage depletion on oil produced from existing wells would encourage more rapid depletion of these reservoirs, but might not encourage additional oil and gas exploration activity.

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[28] Percentage depletion was originally enacted in 1926 as a replacement for recovery based on "discovery values" of oil and gas properties, the determination of which had resulted in substantial litigation. The original statutory rate of 27.5 percent was reduced to 22 percent by the Tax Reform Act of 1969, and was subsequently repealed for integrated producers and phased down for others to 15 percent (for 1984 and thereafter) by the Tax Reduction Act of 1975. The 50-percent net income limitation dates from the industry-wide recession of the 1920s, during which depletion deductions (which were based on pre-recession values) frequently exceeded the income from oil and gas properties. The preference nature of the percentage depletion deduction is specifically recognized in the alternative minimum tax.

Percentage depletion on transferred property

Since 1975, the use of the percentage method for computing depletion deductions for oil and gas wells has been restricted to independent producers and royalty owners for limited amounts of crude oil and natural gas. At the time these restrictions were enacted, Congress recognized that taxpayers would attempt to maximize the amount of oil and gas eligible for percentage depletion by transferring ownership interests. Consequently, the 1975 Act specifies that the limitation on the amount of oil and gas eligible for percentage depletion is to be computed by aggregating the production of related parties. In addition, the 1975 Act generally disallows percentage depletion with respect to transfers of proven oil and gas property.

An argument for repeal of the anti-transfer rule is that by expanding the amount of oil and gas eligible for percentage depletion, the tax law would provide a more powerful incentive for production, and might prevent the abandonment of marginal wells that otherwise would be permanently closed. Oil and gas exploration activities also would be expected to increase as a result.

An argument against repeal of the anti-transfer rule is that integrated producers would be able to benefit indirectly from percentage depletion by selling productive oil and gas property to independents. The anti-transfer rule also prevents independent producers with less than 1,000 barrels per day of average production from buying proven reserves in order to use up their percentage depletion limitation. A substantial portion of the expected revenue loss attributable to this provision would result from the transfer of properties that are already developed, rather than the transfer of newly discovered oil and gas properties.

Net income limitation

The percentage depletion allowance can be viewed as a tax rate reduction. The 50-percent net income limitation acts to limit the rate reduction to 50 percent of the otherwise applicable income tax rate. For example, where production costs are zero, percentage depletion reduces the tax rate of a 28-percent bracket taxpayer (not subject to alternative minimum tax) to 23.8 percent (85 percent of 28 percent). As production costs rise, the tax rate is reduced from 85 percent of the otherwise applicable tax rate to 50 percent of such tax rate (for production costs at or above 70 percent of gross oil and gas income).[29]

An argument for repealing or modifying the 50-percent net income limitation is that it effectively eliminates the benefit of percentage depletion for producers who have little or no net income from oil and gas properties as a result of high exploration or production costs. Repeal of the net income limitation would allow per-

[29] Consider a 28-percent tax bracket producer with $100 of gross income from oil and gas properties and zero production costs. In this case, net oil and gas income is $100 ($100 of gross income less zero production cost), the percentage depletion deduction is $15 (15 percent of $100), taxable income is $85 ($100 less $15), tax liability on oil and gas income is $23.80 (28 percent of $85), and the effective tax rate is 23.8 percent ($23.80 as a percent of $100 of net income). If production costs are $70, net oil and gas income is $30 ($100 of gross income less $70 of production cost), the percentage depletion deduction is $15 (15 percent of $100), taxable income is $15 ($30 less $15), tax liability on oil and gas income is $4.20 (28 percent of $15.00), and the effective rate is 14 percent ($4.20 as a percent of $30 of net income).

centage depletion deductions to be used against income from non-oil and gas activities, thus providing a potential benefit to producers without net oil and gas income. (Increasing the limitation to 100 percent would not benefit producers without net income from oil and gas properties.)

An additional argument for repealing or modifying the 50-percent limitation is that the alternative minimum tax and passive loss rules provided by the 1986 Act may be sufficient to prevent excessive use of percentage depletion deductions to shelter income unrelated to oil and gas activities.

Taxable income limitation

The 65-percent limitation acts to limit the sheltering of oil and gas income by unrelated tax losses. For a taxpayer subject to the 65-percent limitation, each dollar of tax loss from activities outside the oil and gas business reduces the taxpayer's percentage depletion deduction by 65 cents, resulting in a net shelter of 35 cents of oil and gas income.

An argument for repealing or modifying the 65-percent limitation is that the alternative minimum tax and passive loss rules provided by the 1986 Act may be sufficient to prevent excessive use of unrelated tax losses against oil and gas income. Another argument for repealing or modifying both the 65-percent and 50-percent limitations is that a producer subject to either limitation may have a tax incentive *not to* incur exploratory costs since such costs, in effect, only are partially deductible. This situation arises because each dollar of deductible expense (e.g., exploratory costs) reduces the percentage depletion deduction by 50 cents for a taxpayer at the 50-percent limit, and 65 cents for a taxpayer at the 65-percent limit. Increasing the limitations (for example to 100 percent) would, in effect, make exploratory costs 100-percent nondeductible for taxpayers subject to limitation.

Alternative minimum tax

S. 449, S. 828, and S. 1565 would remove excess depletion of various categories of oil and gas from items of tax preference for the alternative minimum tax. As an alternative measure, S. 234 would allow a taxpayer not able to use the benefits of percentage depletion by reason of being subject to the alternative minimum tax to carryforward excess percentage depletion to the next succeeding year.[30] The taxpayer then could use the deduction if it is not subject to the minimum tax in that succeeding year. This latter provision would allow a form of income averaging between minimum tax and regular tax years.

In enacting the various amendments to the alternative minimum tax rules in the 1986 Act, Congress attempted to make the U.S. tax system more equitable for all taxpayers. Congress concluded that the minimum tax should serve one overriding objective: to ensure that no taxpayer with substantial economic income could avoid significant tax liability by using exclusions, deductions and credits. Because excess percentage depletion represents depletion deduc-

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[30] The 1989 Act contains a provision that allows corporations a minimum tax credit in succeeding years for any minimum tax paid by reason of the preference for percentage depletion.

tions in excess of the taxpayer's basis in the depletable property (i.e., it represents deductions not actually paid by the taxpayer), Congress concluded that it should be considered an item of tax preference. It can be argued that to treat excess percentage depletion otherwise would be contrary to the purpose of the alternative minimum tax and would weaken the equity that the 1986 Act's amendments strived to create. To the contrary, others argue that the negative impact of the alternative minimum tax on domestic oil and gas exploration and production activity has been substantial, and that significant tax incentives are necessary in order to increase such activity.

3. Treatment of Surface Casing Costs

Present Law and Background

IDCs generally are limited to expenditures for items which do not have a salvage value (Treas. Reg. sec. 1.612-4(a)).

The Internal Revenue Service has ruled that, under present law, the cost of casing (including surface and production casing) and associated equipment must be capitalized and recovered through depreciation deductions, since the casing is deemed to have a salvage value.[31] Labor and other costs of installing the casing may be deducted as IDCs.

Proposals

S. 234 (Senator Boren)

Under S. 234, surface casing costs would be treated similar to IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, surface casing costs would be treated similar to IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

Analysis

Surface casing generally is installed only after the producer has determined that production from the well is commercially viable. Allowing surface casing costs to be expensed rather than capitalized would tend to encourage development of proven properties. Thus, the proposal probably would increase oil and gas production, but only would indirectly affect exploration activity.

A general tax policy principle is that the costs of acquiring or producing an asset with a useful life or more than one year should be capitalized rather than expensed. Under present law, an exception from this principle is made in the case of IDCs. The proposal would expand this exception, increasing the preferential tax treatment of the oil and gas industry relative to other sectors of the economy.

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[31] *See*, Rev. Rul. 70-414, 1970-2 C.B. 132; Rev. Rul. 78-13, 1978-1 C.B. 63.

4. Treatment of Geological and Geophysical Costs

Present Law and Background

Under present law, geological and geophysical ("G&G") expenditures for the purpose of identifying and locating productive mineral properties must be capitalized and recovered through depletion deductions. These may include expenditures for reconnaissance surveys over a broad area, and more detailed surveys within an identified area of interest. G&G costs may be deducted as an ordinary business loss (sec. 165) if the entire area of a survey is abandoned as a potential source of mineral production.[32]

Proposals

S. 41 (Senator Nickles)

S. 41 would treat domestic (including U.S. possessions) G&G costs in the same manner as IDCs, effective for costs paid or incurred after the date of enactment.

S. 234 (Senator Boren)

Under S. 234, domestic (including U.S. possessions) G&G costs would be treated in the same manner as IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, domestic G&G costs would be treated in the same manner as IDCs for tax purposes, effective for costs paid or incurred after the date of enactment.

Analysis

Under present law, G&G costs generally are recovered less rapidly than IDCs, since IDCs are not required to be capitalized and recovered through depletion deductions. The relatively less generous tax treatment of G&G costs relative to IDCs may be viewed as inequitable. Moreover, to the extent that G&G activity and exploratory drilling are substitutable methods for finding oil and gas reserves, the less favorable treatment of G&G costs relative to IDCs may bias exploration activity against G&G surveys. Providing taxpayers an option to expense G&G costs would reduce this tax bias against G&G activity.

An argument against expensing of G&G costs is that, under the uniform capitalization rules of the 1986 Act, taxpayers are required to capitalize most costs attributable to the production of inventory property and long-term construction contracts. Expensing of G&G costs would provide significantly more favorable tax accounting treatment to the oil and gas industry than other sectors of the economy.

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[32] See, Rev. Rul. 77-188, 1977-1 C.B. 76; Rev. Rul. 83-105, 1983-2 C.B. 51.

B. Energy-Related Tax Credits

1. Tax Credits for Exploration and Development

Present Law

No tax credit is provided for IDCs or similar expenses related to the exploration and development of domestic oil and gas under present law.

Administration Proposal

The Administration proposal would provide a 10-percent income tax credit for the first $10 million (per year per company) of IDCs attributable to exploratory drilling. A 5-percent credit would be allowed for the balance of the IDCs attributable to exploratory drilling. The credit could be applied against both the regular tax and the alternative minimum tax. However, the credit, in conjunction with all other credits and net operating loss carryovers, could not eliminate more that 80 percent of the tentative minimum tax in any year. Unused credits could be carried forward. The credit would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for a calendar year. This provision would be effective on January 1, 1991.

Other Proposals

S. 41 (Senator Nickles)

S. 41 would provide a 10-percent credit for the first $10 million of qualified investment and a 5-percent credit for any remaining qualified investment. Qualified investment means amounts paid or incurred for ascertaining the existence, location or quality of crude oil or natural gas and for developing reserves of crude oil or natural gas. The credit could offset both the regular tax and the alternative minimum tax. Excess credits could be carried back 3 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment, but would terminate after three years.

S. 234 (Senator Boren)

S. 234 would provide a 20-percent tax credit for the first $1 million of qualified investment and a 10-percent tax credit for the remaining qualified investment. Qualified investment means amounts paid or incurred for ascertaining the existence, location, extent, or quality of crude oil or natural gas, for developing reserves of crude oil or natural gas, and for performing secondary or tertiary recovery on domestic wells. The credit would offset both the regular tax and the alternative minimum tax. Excess credits would be carried back 7 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would provide a 20-percent tax credit for the taxpayer's qualified investment for a taxable year. Qualified investment means amounts paid or incurred (1) for G&G expenditures to ascertain the existence, location, extent, or quality of crude oil or natural gas, (2) for the purpose of developing and equipping crude oil and natural gas wells, and (3) for performing secondary or tertiary recovery on domestic wells. The credit would offset both the regular tax and the alternative minimum tax. Excess credits would be carried back 10 years and forward 15 years. The credit would apply to expenditures paid or incurred in taxable years beginning after date of enactment.

Analysis

An argument in favor of an oil and gas exploration tax credit is that the market may fail to generate a socially desirable level of investment in high risk and research-related activities. For example, the Code reflects this view by providing a 20-percent credit for increases in research and experimental expenditures.

In addition, some argue that the social cost of using oil exceeds its market price. The excess cost, or "premium", is attributable to the national security cost of oil use (including the cost of maintaining the strategic petroleum reserve), and the impact of increased U.S. petroleum consumption on the world petroleum market. Since the market price does not reflect the premium value of crude oil, according to this theory, domestic producers may fail to invest adequately in oil exploration. In this case, tax incentives for exploration and development may be desirable to achieve an adequate supply of petroleum.

Since a tax credit provides only a small benefit to taxpayers with little tax liability, it may be less efficient than a subsidy delivered through a direct spending program. In particular, independent oil producers may receive relatively less benefit from the credit than integrated producers since independent producers generate little or no income from refining or retailing operations. Also, independent producers benefit from full expensing of IDCs and the use of percentage depletion (although these benefits may be limited by the alternative minimum tax).

2. Tax Credits for Marginal Production, Etc.

Present Law

The tax laws do not differentiate between the taxation of income from production from marginal wells and other production. However, present law does provide a 20-percent credit for the amount of qualified research expenditures paid or incurred by a taxpayer during a taxable year that exceeds the average amount of the taxpayer's qualified research expenditures in the base period (generally the preceding three years). The credit is scheduled to expire after December 31, 1990.

Administration Proposal

The Administration proposal would provide a 10-percent tax credit for all capital expenditures on projects that represent the initial application of tertiary enhanced recovery techniques to a property. The credit could be applied against both the regular tax and the alternative minimum tax. However, the credit, in conjunction with all other credits and net operating loss carryovers, could not eliminate more than 80 percent of the tentative minimum tax in any year. Unused credits could be carried forward. The credit would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for a calendar year. This provision would be effective on January 1, 1991.

Other Proposals

S. 234 (Senator Boren)

S. 234 would provide a 10-percent credit for the lease operating expenses, depreciation expenses, depletion (not in excess of basis), overhead expenses, and severance taxes with respect to the production of domestic crude oil which is from a stripper well, heavy oil, or oil recovered through a tertiary process. The credit could offset both the regular tax and the alternative minimum tax. Unused credits could be carried back 7 years and forward 15 years. The credit would apply to oil produced in taxable years beginning after date of enactment.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would provide a 20-percent credit for the lease operating expenses and severance taxes with respect to the production of domestic crude oil which is from a stripper well, heavy oil, oil recovered through a tertiary process, or harsh environment oil.[33] The credit could offset both the regular tax and the alternative minimum tax. Unused credits could be carried back 10 years and forward 15 years. The credit would apply to expenditures paid or incurred after the date of enactment in taxable years ending after date of enactment.

S. 828 (Senators Domenici, Boren, Dole, Nickles, Wallop, Garn, Bingaman, Johnston, McClure, and Gramm)

S. 828 would apply the credit for research and development separately to research relating to the discovery or improvement of tertiary recovery methods for oil and gas. The credit would be at a 10-percent rate. The provision would apply to amounts paid or incurred after the date of enactment and before January 1, 2010.

Analysis

Tax credits for marginal oil and gas production are intended to encourage the development or application of techniques for increasing the amount of oil that can be recovered economically out of a declining reserve. Since the continental United States is a mature

[33] A credit at a reduced rate would be available for certain offshore wells.

oil province, many geologists now believe that improvements in enhanced oil recovery techniques offer much potential for increasing recoverable reserves.

3. Nonconventional Fuels Production Credit

Present Law

Present law provides a production credit equal to $3 per barrel of oil equivalent (adjusted for inflation since 1979) for qualified nonconventional fuels (sec. 29(a)). These fuels include oil or natural gas produced from unusual geologic formations and synthetic fuels derived from coal (including lignite). The amount of the production credit phases out as the unregulated annual average U.S. wellhead price per barrel of domestic crude oil rises above $23.50 (as adjusted for inflation since 1979).

In the case of natural gas produced from a tight formation, the credit applies only to gas which is price-controlled and which is entitled to at least 150 percent of the then applicable gas ceiling price established under section 103 of the Natural Gas Policy Act of 1978 (NGPA). In addition, the credit is inapplicable to any gas production from any property on which a well is located which is subject to an election to receive an incentive price under section 107(d) of the NGPA.

The production credit is available to qualified fuels that are (1) produced in a facility placed in service before January 1, 1991, or from a well drilled before January 1, 1991, and (2) sold before January 1, 2001.

Proposals

S. 234 (Senator Boren)

S. 234 would extend the January 1, 1991 placed in service termination date to January 1, 1996. The proposal also would delete the present-law limitations (discussed above) on the eligibility of gas from tight formations for the credit.

S. 343 (Senators Bingaman and Boren)

With respect to the nonconventional fuels credit, S. 343 would extend for 10 years the placed in service expiration date and the expiration date for sales of qualified fuels. Thus, the credit would apply with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 2001. Moreover, the credit would apply to sales of qualified fuels occurring before January 1, 2011.

The bill also would generally extend the credit to all gas produced from a tight formation.

S. 425 (Senator Domenici)

S. 425 generally would treat gas produced from a tight formation as qualifying for the nonconventional fuels production credit. Thus, the bill would delete the present-law requirements that the price of tight formation gas be regulated and that it be subject to a maximum incentive price level under the Natural Gas Policy Act of 1978. This provision would be effective for taxable years beginning after December 31, 1984. If on the date of enactment, any refund or credit of tax resulting from this legislation would be barred by the statute of limitations, such refund or credit would, nevertheless, be made or allowed if a claim is filed within one year of the date or enactment.

The bill also would permit the credit to offset both the regular tax and the alternative minimum tax. This section of the bill would be effective for taxable years beginning after December 31, 1986.

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 would extend the January 1, 1991 placed in service termination date to January 1, 1998. The bill also would delete the present-law limitations (discussed above) on the eligibility of gas from tight formations for the credit.

S. 2025 (Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, and Hollings)

S. 2025 would provide for the permanent extension of the nonconventional fuels production credit.

S. 2288 (Senators Domenici, Boren, Johnston, Dole, Bingaman, Ford, Simpson, Wallop, and Burns)

S. 2288 would extend the nonconventional fuels production credit for two years, making it applicable with respect to qualified fuels which are produced from a well drilled (or a facility placed in service) before January 1, 1993. In addition, the bill would extend the credit to the production of gas from a tight formation if that gas is (1) produced from a well drilled after May 12, 1990, or (2) produced from a well drilled before May 12, 1990, but only if on that date gas produced from that well was gas that was regulated by the United States as to its price, and for which the maximum lawful price applicable under the Natural Gas Policy Act of 1978 is at least 150 percent of the then applicable price under section 103 of that Act. This latter provision would apply to gas produced after May 12, 1990.

Analysis

The alternative energy production credit was enacted in 1980 when oil prices had doubled within a period of one year. There was extensive interest in the United States to encourage development and production of alternative energy sources. Production of other fuels was to be encouraged by a production credit that was related to the price of oil, rate of inflation, and the BTU content of the fuel relative to that of petroleum.

Since 1981, the price of petroleum on world markets has fallen. Declining oil prices have squeezed the ability of alternative fuels to compete with oil because the costs of producing alternative fuels profitably has been stymied.

On the one hand, it may be argued that it is undesirable to continue the production credit in view of the present noncompetitive economic situation and the prospect that alternative fuels production will need to be subsidized for long periods of time. On the other hand, the credit may be viewed as an investment in research and development for long-term future energy needs. If successful, these could yield significant future benefits.

4. Business Energy Credits

Present Law

A 15-percent energy credit is currently allowed for ocean thermal property. In addition, a 10-percent energy credit is currently allowed for solar energy property and geothermal property. Following the 1986 Act, only the business energy tax credits for the above three categories, plus a credit for certain investments in biomass energy property remained in effect. Although retained in the tax law, the 1986 Act reduced the credit percentage for most of these credits, and provided for the expiration of each of these credits by or before the end of 1988. The 1988 Act extended for one year (through 1989) the credits for solar energy, geothermal energy, and ocean thermal property. Moreover, the 1989 Act included a nine-month extension of these three credits. Each of the remaining business energy credits is currently scheduled to expire on September 30, 1990.

Proposals

S. 914 (Senator Matsunaga)

S. 914 would extend through December 31, 1994, the current business energy credits for solar energy property, geothermal property, and ocean thermal property.

S. 2025 (Senators Heinz, Moynihan, Durenberger, Danforth, Symms, Boren, Levin, McCain, Cochran, Burns, Akaka, Cohen, Hollings)

S. 2025 would provide for the permanent extension of various tax provisions that are currently scheduled to expire. Among these, the bill would extend permanently the current business energy credits for ocean thermal property, solar energy property, and geothermal property.

Analysis

The issues with respect to business renewable energy tax credits generally are (1) whether the credits have been available for a sufficiently long period of time to encourage production and sales at efficient, self-sustaining levels, and (2) if such production levels have not been reached, whether those levels will be attained solely because a tax credit is available.

5. Alcohol Fuels Credit and Related Provisions

Present Law

Alcohol fuels credit

An income tax credit is provided for alcohol used in certain mixtures of alcohol and gasoline (e.g., gasohol), diesel fuel, or any other liquid fuel which is suitable for use in an internal combustion

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engine if the mixture is sold by the producer in a trade or business for use as a fuel or is so used by the producer (sec. 40(b)(1)). The credit also is permitted for alcohol (e.g., qualified methanol fuel) which is not in a mixture with gasoline, diesel, or other liquid fuel which is suitable for use in an internal combustion engine, provided that the alcohol is used by the taxpayer as a fuel in a trade or business or is sold by the taxpayer at retail to a person and placed in the fuel tank of the purchaser's vehicle (sec. 40(b)(2)). The credit is equal to 60 cents for each gallon of alcohol used as fuel. The credit is scheduled to expire after December 31, 1992.

Excise taxes

Excise taxes on gasoline, diesel fuel, special motor fuels, trucks and truck trailers, and truck tires make up the sources of tax revenue for the Highway Trust Fund (sec. 9503). The Highway Trust Fund taxes are scheduled to expire after September 30, 1993. Through that expiration date, an excise tax of 9 cents per gallon generally is imposed upon gasoline (sec. 4081), and an excise tax of 15 cents per gallon generally is imposed upon diesel fuel used in diesel-powered highway vehicles (secs. 4041(a)(1) and 4091). Also, an excise tax of 9 cents per gallon generally is imposed on certain special motor fuels (e.g., benzol, benzene, naphtha, and liquefied petroleum gas) used as fuel in a motor vehicle or motorboat (sec. 4041(a)(2)).[34]

Special reduced excise tax rates are applicable to certain fuel mixtures. Gasohol (i.e., any mixture of gasoline containing at least 10 percent alcohol) is subject to a reduced excise tax of 3⅓ cents per gallon, rather than the general rate imposed upon gasoline of 9 cents per gallon (sec. 4081(c)). Diesohol (i.e., any mixture of diesel fuel containing at least 10 percent alcohol) is subject to a reduced excise tax of 9 cents per gallon, rather than the general rate imposed upon diesel fuel of 15 cents per gallon (secs. 4091(c) and 4041(k)(1)(A)). Methanol and ethanol fuels (i.e., any liquid at least 85 percent of which consists of methanol, ethanol, or other alcohol produced from a substance other than petroleum or natural gas) is subject to a reduced excise tax of 3 cents per gallon (sec. 4041(b)(2)). An excise tax rate of 3 cents per gallon also applies to special motor fuels otherwise subject to tax under section 4041(a)(2) (e.g., benzol, benzene, naphtha, and liquefied petroleum gas) if the fuel contains at least 10 percent alcohol (sec. 4041(k)(1)(B)). The excise tax rate is 4½ cents per gallon in the case of any liquid at least 85 percent of which consists of methanol, ethanol, or other alcohol produced from natural gas (sec. 4041(m)).

Analysis

The main issue involving the alcohol fuels credit and exemption is whether these provisions should be allowed to expire as currently scheduled, or whether they should be extended (and if so, for how long). The excise tax exemption and the alcohol fuels credit were enacted to encourage conservation of petroleum by providing

[34] The Code provides for various nonhighway use exemptions (generally via refunds or credits) from the excise taxes imposed on gasoline, diesel fuel, and special motor fuels. *See, e.g.*, secs. 4093, 6416, 6420, 6421, and 6427.

an incentive for production of gasohol mixtures which would reduce the amount of petroleum used in producing gasoline and stimulate the production of usable fuels from renewable sources. In an environment characterized by limits on the exploitation of natural resources, the substitution of ethanol produced from renewable plant matter for non-renewable petroleum products may be socially desirable. Tax subsidies for the renewable fuels industries are intended to increase reliance on renewable resources.

National security concerns may be addressed by increasing U.S. self-sufficiency in energy production. To the extent renewable sources of fuel grown domestically substitute for imported petroleum products, the goal of U.S. energy independence is furthered. National security also was a major policy concern when the alcohol fuel subsidies were enacted. The experience during the 1970s of the OPEC oil boycott of the U.S. and the extremely large price increases for petroleum threatened the ability of the U.S. economy to grow at an acceptable pace.

Use of ethanol in a gasohol mixture has been increasing steadily, but such mixtures still account for a modest proportion of gasoline consumption. Gasohol prices at the pump indicate that gasohol may not be competitive with gasoline without the subsidy in the form of the excise tax exemption or the alcohol fuels tax credit.

Support for the ethanol subsidies also is based on the claim that ethanol production leads to increased income for farmers who produce corn (which is the primary commodity used in producing ethanol) and has favorable effects on the farm price support program. Some doubt about the benefits of the ethanol program for the overall farm programs has been expressed by several observers.[35]

In addition, it has been raised by some that the alcohol fuels credit operates in a relatively inefficient manner. It has been argued that methanol could be utilized and is an easily obtainable substitute. Because methanol is less costly to produce, it might not require a government subsidy. Moreover, methanol also would be an environmentally beneficial substitute, it has been contended, since it is a relatively clean-burning fuel.

Some experts have questioned whether the alcohol fuels subsidies provided by the Code have a significant impact on the environment. Certain gasohol mixtures reduce automobile exhaust emissions of oxides of nitrogen, hydrocarbons, and particulates because 10 percent less gasoline is in the fuel mixture, but those benefits are offset by increases of more volatile emissions, e.g., ozone. Some contend that, on balance, the ambient air tends to remain about as polluted as it was without the use of these additives but with a different mixture of pollutants.[36]

[35] *See, e.g.*, U.S. Department of Agriculture, *Ethanol: Economic and Policy Tradeoffs*, January 1988.

[36] Library of Congress, Congressional Research Service, "Emissions Impact of Oxygenated (Alcohol/Gasoline) Fuels," (CRS Report 87-436 S), May 20, 1987.

C. Other Energy-Related Provisions

1. Statute of Limitations for Certain Underpayments of Tax

Present Law

Except as provided in regulations, the crude oil windfall profit tax, prior to its repeal, [37] was withheld by the first purchaser of the oil from the price paid for the oil. The producer generally was required to file a return (Form 720) only if its windfall profit tax liability exceeded the amount of tax withheld during the calendar year. When required, Form 720 must be filed not later than May 31 of the next succeeding calendar year.[38]

If a producer was not required to file Form 720, the statute of limitations for assessment (or refund) of windfall profit tax runs three years from the due date of the producer's income tax return for the taxable year in which the removal year ends. If a Form 720 was filed, the limitation period runs for three years from the due date of that form.

In Rev. Rul. 85-37, 1985-1 C.B. 302, the IRS took the position that, if Form 720 was required to be filed (e.g., because of an under-withholding of windfall profit tax), but was not filed, the period for assessment is unlimited.

Proposal

S. 41 (Senator Nickles)

Under S. 41, for statute of limitations purposes, the producer would not be treated as having been required to file a windfall profit tax return if the amount of tax withheld by the first purchaser with respect to any oil was not less than the amount required to be withheld as shown on the return filed by the first purchaser. Thus, in such cases, a three-year statute of limitations would apply, measured from the due date of the producer's income tax return. This provision would be retroactive to the original effective date of the crude oil windfall profit tax.

Analysis

An unlimited assessment period generally is applied in cases where the IRS could not reasonably be expected to have notice of a taxpayer's failure to pay the correct amount of tax (e.g., in the case of failure to file a required return). Allowing a limited assessment period where no return was filed would be contrary to this policy. On the other hand, it may be argued that a producer who relied on the first purchaser's finding that no windfall profit tax was due should be treated in the same manner as a producer that was not required to file a return.

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[37] The tax was repealed by section 1941 of Public Law 100-418, effective for oil removed after August 23, 1988.

[38] The first purchaser of oil was required to file quarterly returns of withheld tax, including information necessary to facilitate coordination of withholding by the purchaser with the determination of tax on the producer of the oil.

2. Uniform Capitalization Rules

Present Law

The uniform capitalization rules generally require certain direct and indirect costs allocable to property to be included in inventory or capitalized in the basis of such property (sec. 263A). In general, the uniform capitalization rules apply to property produced by a taxpayer or acquired by a taxpayer for resale. The uniform capitalization rules do not apply to IDCs (sec. 263A(c)(3)).

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 contains a provision that would extend the section 263A(c)(3) exemption from the uniform capitalization rules to any costs incurred relating to oil and gas exploration and development activities. Such costs would include, for example, lease acquisition and maintenance costs, G&G costs, and costs associated with drilling or completing oil and gas wells. This provision would be effective for costs paid or incurred after date of enactment.

Analysis

In 1986, Congress enacted the uniform capitalization rules. At that time, it was believed that the rules in effect prior to the 1986 Act were deficient in two respects. First, those rules allowed costs associated with the production, acquisition, or carrying of property to be deducted currently, rather than capitalized into the basis of the property and recovered when the property was sold or as it was used by the taxpayer. The result was a mismatching of expenses and the related income. Second, different capitalization rules could apply depending upon the nature of the property in question, possibly creating distortions in the allocation of economic resources and the manner in which certain economic activity was organized. Thus, Congress implemented a single, comprehensive set of rules to govern the capitalization of costs. The bill would exempt an entire industry from the uniform capitalization rules, thus possibly resurrecting some of the same problems and distortions with which Congress expressed concern in 1986.

3. Treatment of Offshore Dismantlement Costs

Present Law

As a general rule, the amount of any allowable deduction or credit is to be taken for the taxable year which is the proper taxable year under the taxpayer's method of accounting used in computing taxable income. Expenses generally may be accrued with respect to a liability when the "all events test" has been met (that is, when all the events have occurred which determine the existence of the liability and the amount of the liability can be determined with reasonable accuracy). However, a special rule provides that, except for certain recurring items, in determining whether an amount has been incurred with respect to any item (i.e., is deductible) during any taxable year, the all events test shall not be treated as met any earlier than when economic performance with respect to that item occurs (sec. 461(h)(1)).

The Code sets forth various principles to be followed in determining the time when economic performance occurs (sec. 461(h)(2)). One such principle deals with services and property provided to a taxpayer. In the case of services provided to a taxpayer, economic performance generally occurs when those services are so provided; for property provided to a taxpayer, economic performance generally occurs when that property is so provided; and if property is used by a taxpayer, it generally occurs as the taxpayer uses the property. A second principle involves services and property provided by a taxpayer. Under this principle, economic performance generally occurs when the taxpayer provides the property or services. The Code also specifies principles to be followed with respect to workers compensation and tort liabilities of the taxpayer, plus it provides authority to the Secretary of the Treasury to prescribe regulations which set forth economic performance rules for other items, and which provide exceptions to the principles discussed above.

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

S. 449 contains a provision that would provide a special rule for determining the time that economic performance takes place with respect to a liability for removal of an offshore oil and gas production facility. Under this special rule, economic performance would be deemed to occur while the facility is in use. Thus, the proposal would permit an accrual basis taxpayer to deduct costs related to the dismantlement of an offshore production facility prior to the time that such dismantlement commences.

Analysis

Advocates of this proposal may argue that if the taxpayer is contractually bound to dismantle its production facility, then the costs of dismantlement are related to, and should be allowable as a deduction against, the income generated from the operation of the facility. Once dismantlement begins, however, there may be no significant income generated by the facility against which the dismantlement costs may be deducted. Moreover, the rules permitting the carryback of net operating losses (as they relate, for example, to the alternative minimum tax) may not provide complete assurance that the taxpayer will get full utilization of the tax deduction for its dismantlement costs.

By contrast, others may argue that taxpayers should not be permitted to deduct expenses until the expenses are economically incurred. The allowance of a deduction for an expense to be paid in the future overstates the actual cost of the expense to the extent that the time value of money is not taken into consideration. That is, the deduction is overstated to the extent that the amount deducted exceeds the present value of the expense. The longer the period of time between deduction and the actual payment of the expense, the greater is the overstatement.

Except for liabilities for certain recurring items, economic performance with respect to which occurs within a brief period after the close of the taxable year, taxpayers in all industries are precluded from claiming deductions for items with respect to which economic performance does not occur during the taxable year. If the proposal were enacted, taxpayers engaged in offshore exploration could be placed at a significant advantage vis-a-vis other taxpayers. Moreover, once an exception such as the one contemplated by the proposal is enacted, one might expect that other similar proposals designed to lessen the impact of the economic performance rules on other industries or groups of taxpayers may arise.

4. Revenue Ruling 77-176

Present Law

Under present law, the receipt of cash or other property in exchange for the performance of services is includible in the income of the person performing the services (secs. 61 and 83). In addition, a person who pays compensation in property other than cash recognizes gain or loss on the transfer of the property (sec. 1001).

The Internal Revenue Service has taken the position that when a driller, equipment dealer, or investor contributes materials and services in connection with the development of an oil and gas property in exchange for an economic interest in such property, the receipt of the economic interest does not result in the realization of income.[39] The contributors are viewed as not performing services for compensation, but rather as acquiring a capital interest through undertaking to make a contribution to the pool of capital.

In Revenue Ruling 77-176,[40] the IRS ruled that where the driller received a working or operating interest in the drill site as well as a separate working or operating interest in the tract exclusive of the drill site, the pool-of-capital doctrine set forth in GCM 22730 applies only to the interest acquired in the drill site itself, since the drill site is a separate property within the meaning of section 614. The owner of the lease is treated as having sold a portion of its interest in the tract exclusive of the drill site and as having paid the driller compensation in an amount equal to the value of that interest. The driller is treated as having received compensation in an amount equal to the value of the tract exclusive of the drill site. The IRS applied this ruling on a prospective basis.

Proposal

S. 449 (Senators Boren, Johnston, Bingaman, Nickles, Domenici, Wallop, and Simpson)

Under S. 449, the holding in Revenue Ruling 77-176 (and in any other regulation, ruling, or decision reaching the same (or a similar) result) would be reversed, and the law would be applied with-

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[39] GCM 22730, 1941-1 C.B. 214.
[40] 1977-1 C.B. 77.

out regard to that ruling. This provision would be effective on the date of enactment.

Analysis

Some may contend that Revenue Ruling 77-176 reversed a long standing IRS position regarding the exchange of oil and gas property for services. They may argue that by requiring the service performer to recognize income in such a case, the ruling discourages the use of joint arrangements to explore for oil and gas within a geologic prospect. Should that ruling be reversed, it is possible that domestic exploration and production activities would increase, as more mineral sharing arrangements would be utilized.

Others may argue that, consistent with general U.S. income tax principles, taxable income should be recognized on any receipt of property in exchange for the performance of services, and that no special exception should be made for the oil and gas (or any other) industry. To the extent that a service provider is permitted only in limited circumstances to defer income recognition with respect to property received, that person may be placed in a significantly advantageous position when compared to other service providers who receive partnership interests or other property in exchange for the services that they render.

5. Oil Import Fee

Present Law

Superfund and Oil Spill Fund taxes on petroleum

An excise tax of 9.7 cents per barrel of crude oil and imported petroleum products is imposed on the receipt of crude oil at a U.S. refinery, the import of petroleum products and, if the tax has not already been paid, on the use or export of domestically produced crude oil. Revenues from this tax, and certain other taxes, are deposited in the Hazardous Substance Superfund ("Superfund"). An additional excise tax of 5 cents per barrel is imposed on the same products, and revenues from this tax are deposited in the Oil Spill Liability Trust Fund ("Oil Spill Fund").

Petroleum products which are subject to tax upon import include crude oil, crude oil condensate, natural and refined gasoline, refined and residual oil, and any other hydrocarbon product derived from crude oil or natural gasoline which enters the United States in liquid form.

The Superfund and Oil Spill Fund excise taxes generally are scheduled to expire after December 31, 1991. The taxes will terminate earlier if cumulative Superfund tax receipts during the reauthorization period exceed $6.65 billion, and under certain other conditions.

Tariff on imported petroleum

Tariffs are imposed on various categories of articles that are imported into the customs territory of the United States. The tariffs generally are imposed at a uniform rate on imports from most noncommunist countries, with separate, higher rates imposed on imports from certain communist nations. Preferential treatment applies to certain imports from developing countries, specified Caribbean basin nations, and Israel. Imports from U.S. insular possessions, where the imported product is not comprised primarily of foreign materials, may be made duty-free.

Tariffs are imposed pursuant to the Tariff Act of 1930, and generally are subject to limitations imposed by the General Agreement on Tariffs and Trade (GATT). An import fee in excess of the GATT level generally is in violation of trade agreements and would subject the country imposing such a tariff to sanctions. However, under an exemption from the GATT, a tariff imposed on national security grounds is not a violation of trade agreements.

Currently, a tariff of 0.125 cent per gallon (5.25 cents per barrel) is imposed on crude petroleum, shale oil, and distillate and residual fuel oils derived from petroleum, with low density (under 25 degrees A.P.I.). For substances with higher densities (testing 25 degrees A.P.I. or more), the tariff is 0.25 cent per gallon.[41] Natural gas, together with methane, ethane, propane, butane, and mixtures thereof may be imported tariff-free. Under the recently negotiated Free Trade agreement with Canada, Canadian petroleum products will (after a phase-in period) be admitted tariff-free.

Import fee authority

Under the Trade Expansion Act of 1962, the President can impose oil import fees or import quotas if it is found that imports threaten the nation's security. Congress may roll back such fees by passing a joint resolution of disapproval; however, this resolution can be vetoed by the President, in which case the fees imposed would continue in effect unless the President's veto is overridden by a two-thirds vote of both Houses of Congress. These procedures for Congressional vetoes and overrides were specified by the Crude Oil Windfall Profit Tax Act of 1980.

Proposals

S. 42 (Senator Nickles)

S. 42 would impose an excise tax on crude oil or any other refined petroleum product that is imported into the United States on or after date of enactment. With respect to crude oil, the rate of the tax would be the excess (if any) of $18 over the price per barrel as established by the Secretary of the Treasury.[42] For other refined petroleum products, the excise tax rate would be equal to $3 plus the tax rate determined for crude oil. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export.

[41] Imports from certain communist countries are subject to a 0.5-cent-per-gallon tariff, regardless of density. A 1.25-cents-per-gallon tariff (2.5 cents, for certain communist countries) also is imposed on certain motor fuels and a 0.25-cent-per-gallon tariff (0.5 cent, for certain communist countries) is imposed on petroleum-derived kerosene and naphthas (except motor fuels).

[42] This price, which is to be determined on a weekly basis under the bill, is the weighted average international price of a barrel of crude oil for the preceding four weeks.

S. 161 (Senators Boren and Kassebaum)

S. 161 would impose an excise tax on any petroleum product that is imported into the United States if the average international price of crude oil for any 4-week period is less than $18, and the product is entered into the United States for use, consumption, or warehousing during the week following such 4-week period. The rate of the tax would be the excess of $18 over the average international price per barrel of crude oil for the preceding 4-week period. The bill provides an exception from the tax for petroleum products which are for export from the United States or for resale by the purchaser to a second purchaser for export. The bill would be effective with respect to sales of imported petroleum products in calendar quarters beginning more than 30 days after date of enactment.

S. 850 (Senators Johnston and Bingaman)

The bill would impose an excise tax on any crude oil, refined petroleum product, or petrochemical feedstock or derivative that is imported into the United States on or after date of enactment. With respect to crude oil, the rate of the tax would be the excess (if any) of $24 per barrel over the most recently published average price per barrel of internationally traded oil. For refined petroleum products and petrochemical feedstocks or derivatives, the excise tax rate would be equal to the excess (if any) of $26.50 per barrel (or barrel equivalent) over the most recently published average price per barrel of internationally traded oil.

Analysis

Some may argue that an increase in imported oil prices caused by an import tax or fee would encourage energy conservation and domestic exploration and production. Moreover, such a tax might lessen the United States' reliance on imported petroleum products and discourage the abandonment of marginal wells. Such a tax might also lessen environmental pollution to the extent that reduced petroleum consumption induced by the increased tax or fee would not be simply shifted to consumption of other fossil fuels (e.g., if increased conservation resulted from the increased tax). This could have a beneficial impact on the "greenhouse effect" if the amount of carbon dioxide released into the atmosphere were correspondingly reduced.

Proponents of an import tax might also contend that such a tax would result in an increased price for domestic oil, since domestic oil competes directly with imported oil. This effect could improve the financial health of domestic oil producers who have suffered from the decline in world oil prices occurring over the past several years.

On the other hand, a tax or fee on imported petroleum would likely increase the costs of domestic manufacturers and decrease their ability to compete against foreign producers in both the domestic and world markets. Statutory devices designed to relieve U.S. exported goods from the impact of the tax may be difficult to administer. It might also be argued that a tax or fee on imported petroleum reflected in higher prices would impose a relatively larger burden on low-income households as compared to high-income households, since poorer households spend a larger portion of their disposable income on non-discretionary uses of petroleum products (e.g., transportation and home heating costs).

Further, the proposal would adversely affect Mexico, Canada, the United Kingdom, and other non-OPEC oil producers who jointly supplied nearly half of the petroleum imported into the United States in 1989.

Finally, in 1989 a number of Senators jointly sponsored Senate Resolution 64, which expressed opposition to the imposition of a fee on imported crude oil and refined petroleum products.[43] Specifically, the resolution expressed objection to the imposition of such a tax on the grounds that the fee would (1) directly increase the costs of production and manufacturing for industries using petroleum products, (2) impair the ability of industries to compete in international markets, (3) directly increase the costs to other users of petroleum products, including those dependent on oil and oil products to heat their homes (and those who use electricity generated from oil), and (4) be borne disproportionately by those industries and geographic regions most dependent on petroleum products.

[43] The Resolution was sponsored by Senator Pell. It was co-sponsored by Senators Chafee, Mitchell, Kennedy, Leahy, Rudman, Cohen, Heinz, Lautenberg, Matsunaga, Humphrey, Jeffords, Kerry, and Metzenbaum.

Prepared Statement of Joseph E. Campbell

INTRODUCTION

Columbia Natural Resources, Inc. is headquartered in Charleston, West Virginia. CNR is a wholly owned subsidiary of The Columbia Gas System, Inc. and performs the exploration, development and production activities in the Appalachian Basin. CNR currently operates 6,700 oil and gas wells in ten states in and adjacent to the Appalachian area.

CNR believes that natural gas is important, not only to the national energy supply but also to the national environment because it is the cleanest burning fossil fuel. On behalf of the American Gas Association, I would like to express the natural gas industry's deep commitment and support for both an extension of the nonconventional fuel tax credit for gas sold through 2003 from wells drilled through 1993; and for the restoration of the credit for tight sands gas.

The American Gas Association (A.G.A.) is a national trade association consisting of 250 natural gas distribution and transmission companies. Collectively, A.G.A.'s member companies deliver close to 85 percent of the nation's natural gas consumption.

SUMMARY OF POSITION

A.G.A. believes an extension of the Section 29 tax credit is in the national interest and vital for the continued development of nonconventional natural gas from Devonian shale, coalbed methane, and tight formations. For the following reasons, we recommend the credit be extended at least an additional two years (to cover gas sold until the year 2003 from qualifying new wells drilled up to 1993) We also recommend reinstatement of the credit for tight formation gas.

ENVIRONMENTAL BENEFITS OF NATURAL GAS

Because natural gas is an extremely clean burning fuel, its increased use can contribute to improved air quality. Therefore, we believe that it is prudent to adopt energy/environmental policies that encourage natural gas production and consumption. The extension of the nonconventional fuels tax credit under Section 29 of the tax code would accomplish these goals, respectively.

Acid rain, ground-level ozone formation, and global warming are the three air quality problems that deserve top-quality remedies. The primary precursors of acid rain are believed to be sulfur dioxide (SO2) and nitrogen oxides (NOx) In both stationary and vehicular applications, emissions of SO2 from natural gas are essentially zero. Emissions of NOx from stationary sources can be cut 10-65 percent by switching from other fuels to natural gas.

Ground-level ozone forms when reactive hydrocarbons and NOx come in contact with sunlight. Using natural gas virtually eliminates reactive hydrocarbons from stationary sources and reduces their emission levels from gasoline-powered vehicles by almost 90 percent. We have already noted that natural gas can achieve the NOx reductions from stationary sources. With regard to mobile sources, a recent study by Professor Enoch J. Durbin of Princeton University indicates that an engine designed to run on natural gas could achieve NOx reductions of 80 percent or more by burning a leaner fuel mixture.

One of the primary causes of possible global warming is thought to be increased concentrations of carbon dioxide (CO2) in the atmosphere. In conventional boilers, natural gas can reduce 30 percent of CO2 reductions as compared to gasoline.

DESCRIPTION OF THE SECTION 29 CREDIT

The Section 29 credit applies to new nonconventional wells—those drilled since 1979 and before the end of this year (Exhibit 1). It covers qualifying production sold from these wells until the year 2001. The drilling deadline was to have ended last year but Congress in 1988 extended it through 1990. The tax credit today is approximately 52 cents per MMBtu for tight formation gas and about 80 cents per MMBtu for gas from other nonconventional sources. However, most tight formation gas cannot actually qualify for the credit. This is because the Section 29 rules require that this gas be sold at a regulated price, and actions taken by the Federal Energy Regulatory Commission (FERC) beginning in 1984 have now effectively decontrolled most tight formation gas. Moreover, the FERC recently issued Order No. 519, which eliminates an incentive price for tight formation gas. In effect, this Order terminates the availability of the credit for any tight formation gas that may have been produced from a well drilled after May 12, 1990. Gas produced from other nonconventional sources is not subject to these restrictions.

The credit was part of the nation's response to the OPEC oil embargo and the gas shortage crises of the 1970's. Congress felt that development of our vast nonconventional gas resources should be stimulated through a production credit which would reduce dependence on imported energy.

Nonconventional gas development is often a less attractive investment due to the higher costs and lower well production rates involved. The wells typically require expensive fracturing techniques and other technology to stimulate production to commercial levels. Further, it can take 30 years or more to deplete the recoverable gas reserve. With coal seam gas, for example, we find the initial investment can run 10-20 more than for a conventional well. This is due to the higher costs of stimulating and completing multiple seams, additional compression and production equipment, and facilities for the disposal of the water produced with this gas. In addition, monthly well operating costs can run 300-400% more.

Beyond that, geological factors increase the impact of price volatility risks to these wells. The effects of hydrostatic pressure, which exist in most coal seam gas wells, eliminate the options of temporarily shutting in a coal seam well or reducing its gas flow rate in response to changing market conditions. Similarly, the limited flow rates of tight formation wells make recovery of cash flow disruptions virtually impossible. These and other factors differentiate risks inherent in nonconventional wells as compared to conventional wells.

We believe the credit is a cost effective incentive for this kind of production. Much of this resource base consists of well-known, shallower reservoirs found in proximity to existing pipelines. The gas therefore can be produced directly into the marketplace with less cost, risk and delay than that typically associated with new exploration drilling. This benefits consumers and enhances industry competitiveness through increased supplies of gas and lower prices. The need for this gas becomes more immediate as the current so-called "gas supply bubble" disappears.

The credit is also cost effective because it is solely based on the amount of production actually sold into the market during the initial phase of a well's life. If the well is unsuccessful, no credit is available, and all of the risk of drilling stays with the producer. Further, the credit applies only to the extent sufficient price incentives in the marketplace are lacking. The credit is designed to phase out as the price per barrel of oil rises above $23.50 and terminates completely at $29.50, adjusted for inflation. On a Btu equivalent basis, these phaseout thresholds equate to $4.05 and $5.08 per MMBtu, respectively.

THE CONTINUED NEED FOR THE CREDIT

For the last several years, general market conditions have been nowhere near the $4-5.00 per MMBtu levels indicated above. The recent wellhead price offered for new gas has in many cases fallen below $2.00 per MMBtu. Thus, without the credit after 1990, many producers simply would not have economic margin to develop nonconventional gas sources, and a large amount of our nation's proven reserves would be rendered unavailable to consumer markets.

This is confirmed by results of a May 1988 DOE assessment. Exhibit 2 is taken from the report and shows that nonconventional gas resources comprise approximately 259 Tcf or about one-fourth, of estimated remaining resources in the lower 48 states. However, 61% of the potential tight formation, 68% of the potential shale, and 83% of the potential coalbed methane resources are shown on this exhibit as not economically recoverable at prices less than $3.00 per Mcf.

However, even at a current noneconomic price of $2.00 per Mcf, the Section 29 tax credit enhances the price for shale and coal seam gas by approximately $.80 per Mcf, and tight sands gas by $.52 per Mcf.

The tax credit has been successful in stimulating drilling for this type of gas as shown by the data compiled by the Energy Information Administration (EIA) on Exhibit 2. This exhibit indicates marked increases in the number of new nonconventional wells and the total production of gas from 1980 when the tax credit became effective. The total number of nonconventional wells as a percentage of all post-NGPA wells has risen from 6.7% in 1980 to 18.3% in 1987. The total amount of nonconventional production as a percentage of the total of all post-NGPA new gas production has also risen from 3.9% to 10.6% during this same period. That this has occurred as gas prices were falling is strong evidence that the Section 29 credit was working as an effective incentive.

ELIMINATE SPECIAL RULES FOR TIGHT FORMATION GAS

Gas produced from tight formations must meet special rules. First, to be eligible for the credit, the price of tight formation gas must be a regulated price. This presents an immediate impediment to the production of tight formation gas. The impediment is an outgrowth of the categorization of natural gas wells under the Natural Gas Policy Act of 1978 (NGPA). A well qualifying as a tight formation well under the NGPA nearly always also qualifies under another category of gas, much of which has been deregulated under the terms of the NGPA.

The FERC has determined that a producer whose gas qualifies under either a regulated price category or a non-regulated price category must choose the non-regulated price category. Because much of the gas that qualifies as tight formation gas also qualifies as non-regulated gas, producers are, therefore, required to choose a non-regulated price for their gas. Consequently, the tight formation gas is not eligible for the tax credit for production of nonconventional fuels in many cases. In effect, this has terminated unfairly the credit for existing wells by up to 15 years before it was otherwise scheduled to expire under the Internal Revenue Code.

The price regulation requirement also presents a potential future problem. As a result of the Natural Gas Wellhead Decontrol Act of 1989, gas will be decontrolled no later than May 15, 1991 (for wells spudded after enactment) or January 1, 1993 (for wells spudded before enactment). Therefore, if the credit were to be extended so that it is available for wells drilled after December 31, 1990, tight formation gas from a new well would not qualify for the credit, because it has no regulated price. In effect, this would deny the credit by eight years or more for new wells before it is scheduled to cease under the Internal Revenue Code.

Second, the FERC recently issued Order No. 519,[1] which will eliminate an incentive price that applies to gas produced from tight formations. Elimination of this incentive price effectively makes it impossible for tight formation gas to meet the requirement under Section 29(c)(2)(B)(ii) that the price of such gas be at least 150 percent of the price for NGPA section 103 gas. The Order affects all tight formation gas where the well is spudded or recompleted after May 12, 1990 and all production enhancement gas where the production enhancement work is begun after that date.

Elimination of this incentive price, because of the operation of contracts in the industry, will cause the price of tight formation gas to fail to meet the second special requirement found in section 29 for tight formation gas. In essence, Order 519 will accelerate the already premature expiration of the credit for gas produced from new tight formation wells to May 12, 1990.

In FERC Order 523, which interprets the effective date of the Decontrol Act of 1989, the FERC ruled that gas, even temporarily released from a contract in effect on the date of enactment of the Decontrol Act, is not regulated during the period of release. This interpretation, in effect, deregulates released gas retroactively to July 26, 1989, thus eliminating the tax credit for otherwise eligible gas.

To rectify the special rules that cause the premature termination of the credit for tight formation gas, A.G.A. recommends repeal of the price regulation requirement and the minimum price of 150 percent of Section 103 requirement, both of which are found in subsection 29(c)(2)(B) of the Code. This change would place gas produced from tight formations on the same footing as gas produced from Devonian shale, coal seams, and other sources with respect to qualifying for the credit.

COALBED METHANE

Coal is formed by chemical and thermal alteration of organic materials. This process is called coalification. Methane is a by-product of the coalification process, along with water. Each ton of coal generates up to 5 Mcf of methane, which is more gas than coal can store. Some gas is naturally released, however most of the gas is trapped in conventional reservoirs that overlay coal. The gas retained in coal is coalbed methane. Gas is absorbed on coal surface and held there by pressure.

Coal is 90 percent organic. Conventional gas-bearing rock is almost 100 percent inorganic. Naturally occurring fractures are extensive in coal reservoirs. Fractures are called cleats. Coal is brittle and weak. Therefore, coal tends to collapse into the wellbore, thus permitting gas to be absorbed onto internal surfaces of coal. In contrast, gas is held freely in pores of conventional gas-bearing sources. Coal can hold 2 to 3 times more gas in place as the same volume of a conventional source. This makes coal a very attractive reservoir.

The total resource base is estimated at 400 Tcf in 13 basins. About 90 Tcf to 100 Tcf are technically recoverable. The most active basins currently are San Juan and Black Warrior basins. Approximately 1,000 completed wells currently in each basin will account for 80 percent of 1 Bcf/day of coalbed methane production projected for

[1] 55 Fed. Reg. 6367 (February 23, 1990).

1991. There is also production activity in 5 other basins: Piceance, Raton, Northern Appalachian, Western Washington and Powder River.

The San Juan Basin has an estimated 88 Tcf of reserves, but 38 Tcf are in thin, discontinuous seams that are not yet an exploration target. It has 8 producing fields. Coal seams are found at depths of 1,000 to 3,500 feet. The seams are thick, approximately 20-plus feet. Gas in place is up to 35 Bcf/sq. mile. The Black Warrior Basin has an estimated 20 Tcf of reserves in 9 producing fields. Coal seams are found at depths of 500 to 4,500 feet. The seams here are thin, between 1 to 5 feet thick. Gas in place is up to 9 Bcf/sq. mile.

Unlike conventional gas wells, coalbed methane wells can take 6 months to 4 years to reach peak production. In fact, only water is produced initially. Additionally, water disposal can be costly, particularly if it is low quality. Peak production for some wells in the San Juan Basin is 7 MMcf/day to 10 MMcf/day. This is higher than for most conventional onshore wells. This production is comparable to offshore and ultra-deep onshore wells. Production lives of coalbed methane wells are longer than expected. Some wells in the Black Warrior Basin were drilled in the mid-70s and are now only reaching economic limit. Some wells in the San Juan Basin should have lives of 20 years or more.

The Section 29 credit is critical for coalbed methane wells, because absent the credit most wells would not be producing today. Furthermore, absent significant improvements in market incentives (prices) and/or technology, coalbed methane wells will simply not be drilled.

DEVONIAN SHALE

Gas containing Devonian Shale underlies an area of approximately 273,000 square miles, slightly more than 6 times the size of Pennsylvania. Two-thirds of this is in the Appalachian Basin, the remainder being in the Michigan and Illinois Basins.

The Devonian shale is a very fine-grained, laminated formation created by the disposition of clay and muds as sediments. The shale is essentially comprised of multiple, alternating layers of organically rich black shales which act as both source and reservoirs for the gas, and organically lean gray shales that when fractured, also act as reservoirs. A high carbon content develops in the organic material trapped in the deposit process. Natural gas is generated through a combination of temperature and pressures created as the shale was buried. Since the shale is compacted mud and clays with occasional silt and sand stringers, one can easily understand that any flow of gas within the environment is very difficult.

It is estimated that 25% of new electric generation capacity, coming into service in the next decade will be using gas turbins. The production from the Devonian shale is ideally suited for the energy requirements for these energy projects. This low volume, low pressure reservoir has a very long production life. It is the low volume deliveries that affect the economic rate of return and deters development of these reserves.

DOE estimates that the total gas in place for Devonian shale ranges between 200 and 2,500 trillion cubic feet of gas. A trillion cubic, broken down on the basis of 200 million cubic feet of reserves per well, is approximately 5,000 wells. Or 500 wells per year for 10 years. In real terms, it means that the natural gas industry will be spending $100 million per year to drill these wells. The Natural Gas Industry would pay $15 million annually in wages and salaries. The Appalachian Basin, one of the more economically depressed areas of the United States, would have the equivalent of approximately 750 additional jobs involved to develop gas reserves that will offset importing 160 million barrels of oil; $3.2 billion worth of oil at $20/bbl. If there is any substance to the values of $40 to $140/bbl that have been quoted as the actual cost of getting a barrel of oil out of the Persian Gulf, that could be as much as $22.5 billion worth of oil.

The American Gas Association supports an extension of the Section 29 tax credit for Devonian shale for the following reasons. First, it has been demonstrated that the tax incentive is an effective means of stimulating gas reserve development. It is necessary to justify the economics for wells that have a very low production rate and a very long production life. As previously pointed out, the amount of this reserve base that can be developed depends on the price of natural gas. From the data the Department of Energy has developed, there will continue to be a diminishing "window" of reserves that can be developed from this resource base at an incentive price slightly higher than the free market price of natural gas. The true value of this resource will have to be determined by the goals of our national energy strategy.

Second, Devonian shale, some that have produced for 80 years, have an extremely low production rate after their early production life. Wells that produce less than 10

Mcf/day can be very marginal to operate in their later stages of production, but in the case of the Devonian shale it is not uncommon to see a well average 5 Mcf/day for 20 years. This would account for 36,500 Mcf of gas, the reserves lost by not being able to economically produce this gas would require a new well to be drilled to replace these reserves for every 5 of these older wells that are plugged. An extension of the tax credit will greatly influence the continued production of these "stripper" wells.

SUMMARY

Nonconventional reserves like, tight sands, coal seam and Devonian shale, require a higher than normal investment to release low volume deliveries from their extremely tight geological formation. These low volumes will continue to be produced over what is considered in the industry to be an exceptionally long production life. The recovery of these reserves is purely based on economics. Development of these natural resources must have a competitive rate of return on the investment and have a reasonable payout. Increased use of natural gas can make dramatic reductions in emissions of the precursors to such environmental problems as: global warming, acid rain and ground-level ozone formation. Passage of our Section 29 recommendations will help to ensure an adequate supply of natural gas to support increased demand and reduce reliance on international oil.

CONCLUSION

A.G.A. recommends that the Section 29 tax credit continue as part of our national energy policy and be extended at least another two years for new wells and qualifying production In addition, we urge this Committee to eliminate the special rules for tight formation gas. Over the last 10 years, the Section 29 tax credit has proven itself to be a cost-effective means for stimulating substantial additions to the nation's natural gas reserve base. The importance of an extension and the elimination of the special rules is underscored by our dependence on imported oil again by-over-half and the general slowdown in conventional gas drilling.

EXHIBIT 1

TABLE 1. TOTAL UNITED STATES GAS RESERVES AND RESOURCES ASSESSED

	TECHNICALLY RECOVERABLE GAS, Tcf*	RECOVERABLE GAS BY PRICE** <$3./Mcf	RECOVERABLE GAS BY PRICE** $3.-5./Mcf
LOWER 48 (Conventional)			
PROVED RESERVES, 12/31/86, ONSHORE AND OFFSHORE	159	159	...
INFERRED RESERVES/ PROBABLE RESOURCES, 12/31/86, ONSHORE	85	85	...
INFERRED RESERVES, 12/31/86, OFFSHORE	23	23	...
EXTENDED RESERVE GROWTH IN NONASSOCIATED FIELDS, ONSHORE	119	56	18
GAS RESOURCES ASSOCIATED WITH OIL RESERVE GROWTH***	61	30	11
UNDISCOVERED ONSHORE RESOURCES	219	88	59
UNDISCOVERED OFFSHORE RESOURCES****	134	54	28
SUBTOTAL	800	495	116
LOWER 48 (Unconventional)			
GAS IN LOW-PERMEABILITY RESERVOIRS	180	70	49
COALBED METHANE	48	8	4
SHALE GAS	31	10	5
SUBTOTAL	1,059	583	174
ALASKA			
ALASKA RESERVES	33	7#	0
ALASKA INFERRED RESERVES (COOK INLET AREA)	3	3	0
ALASKA UNDISCOVERED, ONSHORE AND OFFSHORE	93	2#	2#
SUBTOTAL	1,188	595	176
TOTAL	1,188	595	176

*Volumes of gas judged recoverable with existing technology

**Volumes of gas (Tcf) judged recoverable with existing technology by Review Panel at wellhead prices shown (1987$)

***Judged at oil prices of <$24/bbl and $24-40/bbl

****Outer Continental Shelf

#Component in southern Alaska

Source: U.S. Department of Energy, Office of Policy, Planning & Analysis "An Assessment of the Natural Gas Resource Base of the United States", May 1988.

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Number of Producing Wells and Annual Production in Lower 48 States by Post-NGPA Category 1978-1987 (Volume in Billion Cubic Feet)

	NGPA Section 107 Devonian Shale, Coal Seam & Other[1]		NGPA Section 107 Tight Formations[2]		All New Post-NGPA Production[3]	
Year	Number of Producing Wells	Total Production (Bcf)	Number of Producing Wells	Total Production (Bcf)	Number of Producing Wells	Total Production (Bcf)
1978	3,981	101	241	14	102,681	3,684
1979	4,202	94	1,059	40	124,785	5,845
1980	4,756	90	5,351	211	151,934	7,683
1981	5,883	91	12,169	495	187,779	9,637
1982	7,367	98	19,774	719	220,047	10,862
1983	8,405	103	25,537	838	244,682	11,189
1984	9,470	112	31,981	1,058	271,620	13,043
1985	10,626	116	38,184	1,201	293,696	13,477
1986	11,255	124	42,470	1,234	304,194	13,648
1987	11,649	145	45,178	1,413	309,803	14,708

[1] Includes reported production enhancement wells.

[2] Includes tight formation wells qualifying under other NGPA categories.

[3] Excludes old gas production under NGPA Sections 104, 105, and 106.

Source: Tables FE1-FE3, September 1989 Natural Gas Monthly, Energy Information Administration, Office of Oil and Gas, Reserves and Natural Gas Division, Title 1 data base.

Exhibit 2

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Prepared Statement of Charles J. DiBona

INTRODUCTION

On behalf of the American Petroleum Institute (API) a national trade association representing over 250 companies involved in all facets of the petroleum business, I appreciate this opportunity to present the industry's views on the domestic oil and natural gas situation and on appropriate public policies.

Although the Federal Government has taken some positive steps in the last five years toward a more rational national energy policy, such as the abolition of the Crude Oil Windfall Profit Tax, the phased decontrol of natural gas wellhead prices, and the development of a large Strategic Petroleum Reserve (SPR), further changes in public policy are needed. The following discussion outlines trends in U.S. petroleum consumption, production and imports, and then focuses on desirable public policies. While the discussion concentrates on oil and natural gas, which together comprise about two-thirds of the nation's total energy, domestic development of all economic energy sources is desirable.

THE ENERGY SECURITY PROBLEM

Oil's share of total U.S. energy consumption has fallen since the sharp oil price rise in 1973—from 47 percent in 1973 to 42 percent in 1989—but it remains the nation's principal fuel. The U.S. has become quite dependent upon imported oil, and this dependence is increasing at a rapid rate. In this year's first half, U.S. gross oil imports were 8.4 million barrels per day (MMBD) or essentially 50 percent (49.95 percent) of total U.S. oil consumption, the largest import share ever recorded for a six-month period. This compares with 4.9 MMBD or 31 percent of consumption in 1985, the year before the sharp fall in oil prices.

The fall in oil prices both stimulated U.S. oil consumption and discouraged domestic production. Growth in oil consumption accounted for about two-thirds of the rise in imports between 1985 and 1988, while the decline in production accounted for the other one-third. However, the roles of these two factors have changed dramatically since 1988. Consumption stabilized in 1989 and has declined this year, while the downtrend in domestic production has accelerated. Domestic crude oil production now is declining at an annual rate of about 500,000 barrels per day, compared with less than 300,000 barrels per day during the 1985-1988 period. Production in the lower 48 states, which is falling annually by about 400,000 barrels per day, is down to 5.5 million barrels per day, the lowest level since 1950. And Alaskan production, which increased until 1988 and thus helped to offset declines in lower-48 production, now is falling annually by about 100,000 barrels per day.

World oil prices still are low relative to the levels of 1980-1985. However, this situation may not last. Since 1985 the demand for OPEC oil has been increasing, and OPEC's capacity utilization has risen from 60-65 percent in the 1983-1985 period to about 80 percent now. The historical experience suggests that there is increased danger of a substantial oil price rise when OPEC's capacity utilization rate rises above 80 percent. Moreover, oil resources are concentrated in an unstable area of the world where military engagements may curtail the flow of oil, or the threat of military force may be used to restrict the flow of oil from the area, as the recent Iraqi military buildup on the Kuwaiti border suggests.

Drilling activity, which is an advance indicator of production, offers little basis for optimism regarding domestic oil production. So far this year, the number of active drilling rigs and oil well completions are up from last year's severely depressed levels, but they are running at less than one-third of the peak levels of the early 1980s.

Both private and government agencies including the U.S. Department of Energy expect lower domestic oil production, greater U.S. oil consumption, and larger imports in the future. Thus, under current policies the U.S. shortly is likely to import well over half of its oil continuously and perhaps on the order of two-thirds of its oil by 2000. The exact import share will depend heavily on future oil prices, but also on U.S. policy and how it affects domestic production.

This growing U.S. dependence on oil imports increases the risk that the U.S. again will suffer the adverse consequences of an oil supply disruption. Greater U.S. oil import demand reduces the amount of unused oil producing capacity around the world, and therefore it increases the likelihood that a supply cutback by one or more oil exporting nations will cause the world oil price to rise sharply. Greater U.S. oil import dependence also increases the potential adverse effects of a disruption on the U.S. economy. These adverse effects include reduced gross national product, higher inflation, and greater unemployment. Therefore, by holding down the growth in our demand for foreign oil, we can make a supply disruption less likely and also reduce the harmful impact of a disruption should one occur.

DESIRABLE PUBLIC POLICIES

The principal government actions that are needed to develop our domestic oil and natural gas resources and thus slow the growth in oil imports are increased leasing of Federal lands, tax incentives for domestic petroleum development, and the avoidance of regulatory requirements whose benefits are not commensurate with costs.

IMPROVED ACCESS TO FEDERAL LANDS

According to U.S. Department of the Interior estimates, the U.S. has 39 to 82 billion barrels of undiscovered, recoverable oil and natural gas liquids resources, with a mean estimate of 58 billion barrels; and 307 to 507 trillion cubic feet of undiscovered, recoverable natural gas resources, with a mean estimate of 399 trillion cubic feet. The Federal Government owns or manages onshore and offshore lands containing much of these resources. The Interior Department estimates that, for example, Federal offshore areas contain about one-third of the nation's undiscovered, recoverable oil and natural gas resources. If the U.S. is to find and develop new petroleum resources that will reduce our demand for oil imports, Federal lands must be explored. The most promising lands are onshore in Alaska and offshore California and the Gulf Coast. Yet, year after year, through the appropriations process, Congress has imposed leasing moratoriums on promising offshore areas. Furthermore, President Bush's recent decision to reduce severely the offshore acreage available for petroleum exploration and development will harm both the nation's economic performance and its energy security. The results of this policy will be less domestic petroleum production, more energy imports, greater dependency on the OPEC cartel, more tanker traffic, and the export of investment and jobs overseas.

The Coastal Plain of Alaska's Arctic National Wildlife Refuge (ANWR) is an especially promising area. The U.S. Department of the Interior's (DOI) April 1987 report, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment,* concludes that if there is economically recoverable oil in the area, there is a 95 percent chance for more than 0.6 billion barrels and a 5 percent chance for more than 9.2 billion barrels of recoverable oil. The mean estimate is 3.2 billion barrels. Using the mean estimate of 3.2 billion barrels of recoverable oil, the DOS estimates that the ANWR Coastal Plain would have peak production of 659,000 barrels per day.

TAX CHANGES

The exploration/production segment of the domestic petroleum industry has been extraordinarily depressed since oil prices fell sharply in 1986. The reductions in both domestic petroleum production and investment in future production combine to indicate a greatly weakened domestic petroleum supply capability. The removal of tax disincentives and enactment of tax incentives would have a positive effect on investment in exploration and production as well as on enhanced recovery of existing reserves. While these measures are unlikely to halt or reverse the trend of import growth, they can delay and reduce the trend.

REMOVAL OF TAX DISINCENTIVES

There are, under current tax law, several provisions which hinder the exploration for and development of domestic oil and gas reserves. These tax disincentives should be modified. They include:

1. *Geological and Geophysical Costs*—Geological studies and geophysical surveys (G&G) are the initial steps undertaken in evaluating an oil and gas prospect. Currently, expenditures for G&G are recovered through depletion over the life of the field. However, geological and geophysical costs are an important and integral part of the daily exploration process. As such, G&G represents ordinary and necessary business expenses no different from the ordinary and necessary business expenses incurred by the rest of American industry. Therefore, these costs should be allowed to be deducted currently as ordinary and necessary business expenses.
2. *Intangible Drilling Costs*—Under present law, integrated oil producers may deduct only 70 percent of intangible drilling costs (IDC) in the year incurred; the remaining 30 percent is amortized over a period of 60 months. Independent producers may currently' deduct 100 percent of IDCs. The full expensing of IDCs as incurred is by far the most efficient cost recovery mechanism. Current expensing avoids the reduction of anticipated rates of return of any project and the resulting barriers to investment in oil and gas production. At the same time, it does not

impose any long-range reduction in tax revenues. Full expensing of IDCs should be available to all producers regardless of size.

3. *Minimum Tax Preferences*—Under current law, percentage depletion and that portion of IDCs which are expensed are treated as tax preferences for purposes of the alternative minimum tax (AMT). Historically, within the Internal Revenue Code the government has attempted to encourage petroleum industry exploration and development by allowing percentage depletion and current deduction of IDCs. By severely diminishing the value of these regular income tax incentive provisions, the AMT reduces the economic viability of many projects and tends to magnify the intrusion of the tax system into the investment decision process. Both IDCs and percentage depletion should be deleted as tax preferences for determining the alternative minimum tax.

4. *Rev. Rul. 77-176*—The Treasury Department causes taxpayers to use the cumbersome tax partnership rules in order to obtain traditional after-tax economics in typical oil and gas joint ventures., Eliminating the unnecessary burdens of Rev. Rul. 77-176 (e.g., partnership tax returns, separate audits and administrative proceedings) would be beneficial to both the IRS and taxpayers.

5. *Transfer Rule*—Under current law when an independent producer acquires a "proven" producing property from an integrated producer, that property is not eligible for percentage depletion. This discourages transfers of properties from one taxpayer to another who could operate them more efficiently. Absent such a change, properties valuable to the nation's oil supply might well be abandoned as uneconomic, rather than produced.

6. *Net Income Limitations*—Current law provides that the percentage depletion deduction is limited to not more than 50 percent of the net income of an eligible producing property and not more than 65 percent of the taxpayer's taxable income. Repealing these provisions would stimulate additional cash flow to those independent producers who retain income producing properties.

7. *Offshore Abandonment Costs*—When an offshore oil and gas field has exhausted its commercial life, production facilities such as platforms must be removed. Costs incurred for such removal are substantial. Under current law, a taxpayer is not allowed a deduction far those expenses until the taxable year in which such facilities are actually removed. The obligation to remove production facilities is imposed as a condition of obtaining an offshore Federal lease, state permits, etc., and benefits the entire life of the oil and gas project. The cost of the removal and restoration obligation should be recovered over the producing life of the offshore lease.

THE NONCONVENTIONAL FUELS TAX CREDIT

The Section 29 tax credit for producing fuel from a nonconventional source was enacted into law in 1980. The U.S. possesses vast reserves of many of the alternative energy sources eligible for the tax credit. Congress believed that the credit would lead to the development of these domestic sources thereby reducing United States dependence on imported energy. This tax credit, due to expire at: the end of this year, should be extended. Proposals in Congress would: extend the placed in service date from January 1, 1991 to January 1, 1993; remove the price regulation requirement for tight sands gas effective prospectively for wells drilled after July 1, 1989, and treat newly spudded well gas the same as if the gas were produced from old wells; clarify that the credit applies to gas produced from shale and modify the Section 29 treatment of oil and gas produced by retort of shale rock; and, confirm the Department of Energy definition of "tar sands." API endorses these proposals. In addition, we recommend elimination of the requirement that qualified fuels be sold prior to a specified date [January 1, 2001, under current law]. Finally, in order for the incentive to be fully effective, it must be fully creditable against AMT in the year earned, and the full unused portion of the credit must be carried forward and applied against the regular tax or AMT of a subsequent year.

TAX INCENTIVES

In addition to the foregoing proposals, tax incentives also would have a positive impact on domestic petroleum production. The Administration's energy tax proposals in the FY 1991 budget represent a step in the right direction. They are, however, limited in scope and do not provide equal treatment for all petroleum companies. Such disparate treatment restricts the program's potential benefits to the nation.

A program of tax incentives for all petroleum companies without regard to such factors as company size or degree of integration would provide greater national benefits than the Administration's proposal, as would a more comprehensive approach such as that proposed in the domestic Energy Security Act of 1989 (H.R. 664, S. 449).

This legislation would establish much broader incentives than those contained in the Administration's proposal. For example, under H.R. 664 and S. 449, companies would be eligible to receive permanent tax credits for all drilling costs, and for costs incurred to produce stripper oil, heavy oil, oil from enhanced recovery projects, and "harsh environment" oil such as that produced from offshore areas under at least 400 feet of water. In addition, S. 828, the Enhanced Oil and Gas Recovery Act of 1989, which Senators Domenici and Boren along with other members of the Senate have sponsored, would be an important step towards overcoming current obstacles to enhanced recovery for both existing wells and new projects. It would complement H.R. 664 and S. 449.

A recently released study by the U.S. General Accounting Office (GAO) suggests that production incentives are of limited value. However, both the Departments of Energy and Treasury, the only government agencies who are identified as having reviewed the study, dissent from its findings and conclusions. API's brief review (the study has only just been released) concurs with that of DOE and Treasury in that we find GAO's conclusions are not supported. by the information it supplies.

First, GAO's finding that the capital recovery rules for the industry are overly generous fails to account for the particular characteristics of petroleum investment, such as high risk and the lack of any salvage value for major asset categories, which those rules have been designed to address.

Second, the GAO study relies on a flawed theoretical analysis of the petroleum industry's marginal tax rates to make broad comparisons with other industries. Numerous studies using actual data have demonstrated that the burden of taxation borne by the U.S. petroleum industry in recent years is similar to, if not higher than, that borne by other industries. Thus, either the tax rates on the non-production (downstream) operations of the oil industry are extraordinarily high—perhaps even exceeding the statutory rate—or the GAO's estimates of the marginal tax rates in the producing (upstream) segment of the petroleum industry vastly understate the actual rate. Inasmuch as there is no basis to believe the former explanation, it is highly likely that the GAO's estimate of the petroleum producing industry's marginal effective tax rate is simply wrong.

Third, GAO concludes that the U.S. tax system is not a significant factor in the movement of U.S. petroleum activity abroad. Yet the report itself cites dozens of examples of improving terms of petroleum taxation in other countries even as it alludes to the increasing proportion of investment being directed overseas.

Fourth, the GAO's comparisons of the costs of tax incentives with the costs of obtaining SPR oil ignore several important factors. For example, increasing the amount of oil in the SPR raises demand for oil in world markets and puts upward pressure on world oil prices, whereas increasing domestic oil production puts downward pressure on world oil prices. As OPEC capacity utilization rises and the world oil market becomes tighter, this factor becomes more and more important. In addition, the efficacy of SPR additions compared to augmenting domestic production through tax incentives depends critically upon the government's purposes and assumptions. For protection against a short-lived disruption expected to occur within the near future, the SPR is the more appropriate mechanism.

However, if the risk of a disruption is more distant or if it is assumed to be of a long-lasting nature, augmenting domestic production is probably more efficient than adding to the SPR.

Both the Departments of Energy and Treasury have also pointed out that the benefits of proposed tax incentives are not reflected adequately in the GAO report, and they disagree with the major findings of the study.

TAXES ON ENERGY USE

The Federal Government should not use energy taxes to resolve the Federal deficit problem, since such taxes would impose very large costs on the economy. For example, several studies of the potential effects of higher Federal motor fuel taxes or broader based energy taxes, which have been done by private and public organizations, have found that such tax increases would have severe adverse effects on the national economy. These adverse effects include higher inflation, more unemployment, lower real incomes and a loss of international competitiveness for American industry. Because of the damaging effects that energy taxes would have on the economy, the Federal revenues raised by such taxes would in large part be offset by revenue losses from other sources and by higher government expenditures for income maintenance programs. In addition, motor fuels and other energy-use taxes tend to be regressive, falling hardest on relatively low-income people, and also place especially heavy burdens on regions of the country that are particularly heavy energy users.

REGULATORY REQUIREMENTS WITH POSITIVE NET BENEFITS

The government should avoid imposing regulatory requirements where costs exceed the likely benefits, and it should always seek to obtain benefits through the use of the most cost-effective methods. Unnecessarily large pollution control costs reduce the nation's ability to develop its petroleum resources and to produce petroleum products as well as its ability to achieve other objectives, without resulting in compensating environmental benefits.

The petroleum industry now is particularly concerned about the reformulated gasoline mandate contained in Clean Air legislation that is currently being considered. The industry agrees that changes in gasoline will help reduce emissions. We are doing joint research with the automobile industry, testing many different reformulated gasolines to try to establish which vehicle-fuel combination works best. However, a Congressional mandate telling refiners exactly how to reformulate gasoline would make this much-needed research pointless.

Moreover, no one has determined how the fuel specifications in the Clean Air bills would affect overall air quality. Certain of the requirements would actually increase some of the pollutants that cause smog. These requirements would also come at great cost to consumers. Finally, the bills would not provide adequate time to make the refinery changes needed to meet the new gasoline requirements.

To summarize, the petroleum industry favors reformulating gasoline to reduce air pollution. However, the provisions now being considered in Congress may well not provide the best air quality solution at the lowest cost to consumers. An approach that sets realistic performance standards and allows industry scientists working with recognized air quality authorities to find cost-effective solutions is far preferable.

BENEFITS OF RECOMMENDED PUBLIC POLICIES

Taken together, all of the positive steps outlined above increased access to Federal lands, appropriate tax incentives, and the avoidance of unwarranted costly regulations—would stimulate U.S. petroleum production and prevent unnecessary declines. The recommended measures would have important economic benefits as well as national security benefits—for the U.S. and for other oil importing nations as well.

First, as stated above, greater U.S. petroleum production will reduce the future demand for oil on world markets and thus help to hold down the world oil price, thereby benefiting American consumers who in the aggregate are large-net importers of oil.

Second, the U.S. may increase its national income by expending less of its labor, capital, and materials to produce petroleum domestically—from lands that have not yet been leased, for example than it would use to pay for imported oil.

Third, to the extent that increased domestic petroleum production requires the use of specialized labor and equipment that otherwise would be unemployed, increased U.S. petroleum production will raise employment of labor and capital and thus boost national income.

Fourth, lower U.S. expenditures for oil imports will improve the nation's international trade balance.

Lastly, a larger national income means a higher Federal tax base and higher tax revenues. Moreover, leasing of Federal lands and production from them raises lease bonus and royalty revenues for the Federal Government.

THE ROLE OF ENERGY CONSERVATION

Energy conservation is sometimes advocated as the principal mechanism to achieve environmental and energy security goals. The petroleum industry fully supports the efficient use of energy. However, we are convinced that an effective national energy policy cannot be built on conservation *alone*. API has conducted several studies on energy demand and economic performance that lead to this conclusion.

One of these studies examined the relationship between energy use and economic performance. This study found that if energy use is held constant through government-imposed limits, then normal rates of economic growth can be maintained only if more capital or labor are used or if the pace of technological change quickens. Either of these implies a huge increase in investment, on the order of 50 percent of total national investment, and a reduction in aggregate U.S. consumption on the order of 16 percent. It is simply not realistic to expect this to happen. Of course, in the 1970s and early 1980s, the nation adjusted to sharply higher energy prices by using less energy. But this was a period of tenfold oil price increases and below par economic performance. In those years, the reduced use of energy hurt economic growth.

THE STRATEGIC PETROLEUM RESERVE

Finally, the Federal Government should continue to add to the Strategic Petroleum Reserve (SPR), which currently contains about 587 million barrels of crude oil or about 70 days' supply of gross imports at recent rates. The SPR is an important tool for responding to future supply disruptions.

PREPARED STATEMENT OF SENATOR PETE V. DOMENICI

Mr. Chairman, distinguished members of the Committee on Finance.

I am greatly honored to appear before this distinguished Subcommittee to offer some thoughts as you consider various strategies to augment America's domestic reserves of energy.

I am tempted to tell you, Mr. Chairman, that I have the perfect answer to your challenge.

That answer is S. 828, the Enhanced Oil Recovery bill that you and I are sponsoring.

I am convinced that the Tax Code offers a very exciting and quite inexpensive way to meet America's energy needs for this decade and into the next century.

And I should note that it is achieved in a way that lowers the threat to our environment.

America, in my view, must maximize our development of existing oil wells. Surely that should be a premise on which environmentalists, conservationists, and pro-development advocates can agree.

By "maximizing development," I mean getting as much as possible out of each well drilled.

Today, when the oil industry drills a well and extracts all that it normally can extract economically, about *two-thirds of the oil is left behind.* It simply is uneconomic to pump more than a third of the oil from a typical well in today's market.

Let me repeat that: Traditional oil recovery techniques leave *65 to 70 percent of the oil in the ground.*

Yet the science exists to extract far more oil per well. Unfortunately, those techniques are expensive; they require considerable capital investment beyond what is generally economic under today's tax structure. Most of that oil will not be recovered under existing tax policy unless the price of oil rose substantially from today's levels.

Assuming $20-a-barrel oil and existing Federal tax policy, the Department of Energy estimates America's current recoverable petroleum reserves at 26 billion barrels.

To enlarge that supply, you and I, Mr. Chairman, and other Senators, have proposed a modest package of tax incentives—S. 828, the Enhanced Oil Recovery Tax Act of 1989.

This legislation has a very simple goal: Increasing production from existing American wells.

If we assume that the per-barrel price of oil remains at $20, DOE estimates that S. 828 would increase America's economically recoverable oil reserves by 25 percent. The cost in lost Federal revenues for each additional barrel of oil would be no more than 35 cents—less than a penny a gallon.

Let me go through those figures again. S. 828 will mean an *additional 6.9 billion barrels of oil* production—at a total loss in Federal revenues, *spread over several decades,* of $2.4 billion according to DOE.

Last year, the Joint Committee on Taxation estimated that my bill, with several modifications, would cost $13 million in the first year, and would cost $151 million over the five-year period, 1990 to 1994.

That confirms my view that the revenue loss as a result of instituting these incentives would be very minor in the initial years.

You may be interested to know, Mr. Chairman, that DOE says S. 828 will add 428 million barrels to Oklahoma's reserves. In my own state, another 122 million barrels of oil could be recovered economically under S. 828—more than doubling our recoverable reserves, creating 8,000 new jobs by the year 2000.

All these gains would be achieved simply through increased productivity from each well existing now, or each well that would be drilled in any event.

S. 828 means new investment and new jobs—American jobs—raising employment in areas of relatively high unemployment. Inevitably, that will produce a ripple effect as economic activity increases, but I have not included those gains in my calculations.

Mr. Chairman, *this is a time-sensitive challenge. The accelerating rate of well abandonments and well plugging could eliminate. within five years. economic access to as much as two-thirds of the remaining oil that could be recovered through Enhanced Oil Recovery.*

Possibly most important, this legislation will reduce dramatically our dependence on foreign petroleum.

If American consumers were to purchase those 6.9 billion barrels of oil on the world market—as we inevitably will, if we are unable to increase at-home reserves—we will have to pay $138 billion in foreign markets [at $20 a barrel].

And we will watch with some fear as that oil is shipped across the sea; 5,750 voyages of a tanker with the capacity of the Exxon Valdez would be required to move those 6.9 billion barrels of oil to American users.

Last year, the gap between the oil we produced and what we consumed cost us $35.2 billion on our trade deficit. That was 29 percent of the total trade deficit.

Domestic petroleum production is projected to decline from nearly 10 million barrels per day in 1988 to 7.2 million in 2101. Oil imports are expected to reach 13.4 million barrels per day, about two-thirds of total U.S. consumption, by 2010, compared with 6.3 million barrels per day in 1988.

With our oil imports approaching the unprecedented level of 50 percent of consumption, there is an urgent economic need for increased domestic energy production.

Let me cite a few figures that may concern you as much as they concern me:

- The number of oil and gas rigs in operation two weeks ago was 825, the lowest rate since records began to be kept in 1940. In fact, the number of rigs is down 80 percent from the 4,000 in operation in 1981.
- Last year, there were 28,510 wells completed, the fewest since 1973, and 60 percent below the number completed in 1981.
- Footage drilled was 130 million last year, off 70 percent from 1981.
- Capital spending for exploration and production was $14.1 billion last year, off 8 percent from the preceding year and a startling drop from the peak of $57.8 billion in 1981.

Within 10 years, we could be spending $150 billion to $200 billion a year for imported oil. That amount is greater than our total trade deficit today, raising serious questions about our ability ever to reduce the deficit.

Let me return to the example of the Exxon Valdez. Under S. 828, for every tanker the size of the Exxon Valdez that fails to sail for America—and we recover oil instead from enhanced techniques out of wells in Texas or New Mexico or Kansas—the cost over time in direct revenue loss to the Treasury would be $400,000.

But the 1.2 million barrels carried aboard the Exxon Valdez would have a value of $24 million—$24 million spent in the Middle East and added to our trade deficit.

If S. 828 were enacted, the United States could reduce the trade deficit by as much as $50 dollars for every dollar foregone by the Treasury.

I see S. 828 as a painless method—one that can be achieved with no rise in the price of oil to consumers—to expand dramatically America's at-home oil production.

Mr. Chairman, allow me now to list the precise provisions of the Enhanced Oil Recovery Tax Act of 1989:

- The bill provides a 10 percent investment tax credit for the costs of enhanced oil recovery projects.
- The bill creates the what I like to call the "Energy Reinvestment Allowance." It allows a 27½ percentage depletion on the incremental oil produced as result of enhanced oil recovery techniques. The availability of the energy reinvestment allowance is limited to pay back. Pay-back is the point at which the producer has sold enough oil to recoup the investment associated with the enhanced oil recovery project. Under S. 828, current law applies to current reserves.
- The bill suspends the intangible drilling costs and percentage depletion preferences for the alternative minimum tax, so long as the price of oil remains below $30 a barrel. Should the price rise above that $30 figure, most of the benefits to the producers would disappear. I am convinced that a ceiling of less than $30 a barrel would be ineffective, failing to accomplish the goals set out in the legislation.

These enhanced oil recovery incentives [the energy investment allowance, the AMT holidays, and the credit] would be available only until a producer reaches "pay-back," the point where the producer has recovered his investment.

• The bill permits the states to determine which projects would qualify as enhanced oil recovery projects.
• The bill would increase the net income limitation on oil and gas to 100 percent of taxable income.

Before turning to the issue of natural gas, I would like to point out for the benefit of this Subcommittee the important contribution of stripper wells to the nation's energy security, even though each individual well produces less than 10 barrels of oil per day.

Nearly three-fourths of all producing oil wells in this nation fall into the stripper category. Stripper wells often are thought of as being "uneconomic, but consider these statistics from a consumer's viewpoint:

America consists of some 95 million households. We, as a nation, consume roughly 17 million barrels of oil daily. With one barrel of oil meeting the average daily needs of about six families, stripper wells fulfilled the oil needs of about 7.5 million U.S. families in 1988.

Stripper wells generate thousands of jobs in the oil and natural gas fields, hundreds of millions of dollars in payrolls, and account for 15 percent of total U.S. crude oil production. Maintenance and enhancement of stripper well production unquestionably makes economic sense.

Yet we are seeing more and more of these wells being capped. In 1989, 17,423 stripper wells were abandoned out of 454,150. In my state of New Mexico, 1,087 out of 14,723 stripper wells were abandoned that year. About 20.8 percent (14.3 million barrels) of the state's oil production comes from stripper wells.

New Mexico happens to rank seventh in the production of crude oil among all the states. The petroleum industry is still one of New Mexico's largest non-governmental employers, providing jobs for 19,111 men and women in 1989, a decrease of 825 from 1988.

An estimated 39.3 percent (27 million barrels) of the state's 1989 oil yield was produced by using secondary recovery techniques and pressure maintenance where that is economic.

Mr. Chairman, since S. 828 was introduced, I have received many comments from industry, the Administration, and others. Several oil producers have told me that this legislation would increase their domestic reserves by 20 to 30 percent.

One producer wrote: "If enacted S. 828, would not only increase current domestic oil and gas production, but also foster new and innovative extraction techniques, which would substantially broaden our nation's energy base, bolstering our national security interests."

The President has also put forth the outline of his enhanced oil recovery proposal. This is evidence that the President recognizes the important contribution to our energy security that enhanced oil recovery could make. I hope your Committee agrees.

Now, let me turn to the issue of natural gas.

Lately there has been much attention focused on the comparative advantages of natural gas as the "fuel of the future," primarily due to its environmental benefits.

Now that well-head prices of natural gas finally have been decontrolled, the domestic petroleum industry is beginning to look optimistically toward the future of natural gas exploration and production.

However, the economic, political, and technological conditions necessary for successful natural gas development are the same as for crude oil. Both resources are found and developed through the efforts of the same explorers and producers. Often, oil and natural gas are produced from the same wells. It is important to keep this in mind as national energy policy takes shape.

While domestic natural gas supplies are adequate to meet the present needs of American consumers, there are some short-term problems which are primarily related to slack demand. The long-term problems are going to be more Serious as a result of regulatory inefficiencies, which reduce the ability of natural gas producers to compete effectively for markets.

One of the most important questions to consider in these hearing is how to promote regulatory change on both the Federal and state levels which will create a more competitive environment for natural gas.

According to the DOE, total demand for energy will continue to grow, despite energy conservation. Total primary energy consumption is expected to grow at an average annual rate of about 1 percent per year.

Among all the states, New Mexico ranked fourth in the production of natural gas in 1989. At the end of that year, there were 19,221 active gas wells in New Mexico.

The average price of natural gas was $1.60 per thousand cubic feet in 1989, down 14 cents from the previous year and $1.17 below the 1983 high of $2.77.

In a low energy price outlook, there are market opportunities to expand gas demand. However, there also is strong price competition from other fuels, particularly cheap imported fuels.

There are emerging energy needs due to increased concerns about the environment, too. Natural gas is a viable option in competition with low-priced alternative fuels.

The Section 29 credit encourages natural gas producers to drill for hard-to-get natural gas. This includes methods like coal seam gas, tight sands, and coal-bed methane.

After years of research and development, when the price for fuel was high, technology progressed significantly in these areas.

In 1989 the U.S. recovered just under 100 billion cubic feet of natural gas using coal-bed methane gas techniques. In 1990 we expect to recover around 200 billion cubic feet.

With current technology—and prices under $3.00 per 1,000 cubic feet—20 trillion cubic feet of recoverable natural gas exists.

Isn't technology fantastic! For years coal-bed methane was considered a nuisance to mining operations, It was produced to help prevent accidents, not because it could be used for fuel.

Now, after years of research and development, coal-bed methane is becoming recognized as a viable and abundant domestic energy resource. The government counts it in resource estimates, and it's keeping America's gas reserves from slipping while other new gas developments are temporarily slow.

In the San Juan basin along the New Mexico-Colorado border, the first coalbed methane development began in 1977. That first well didn't start producing until 1981. It eventually produced 2.4 billion cubic feet a day. Some wells average more than 5 million cubic feet per day and peak at around 10 million cubic feet a day.

Increased gas supply, however, cannot be obtained under a continuation of current industry practices. New initiatives will be required to increase production. Without the new initiatives for gas supply, U.S. gas supply would decline, and the gas industry would be unable to take advantage of the opportunities for increased sales.

In fact the gas industry would face an increasingly supply-constrained situation to meet even current levels of gas sales.

While there is not much natural gas imported today, those imports are projected to grow rapidly during the 1990s. It is estimated that American production will drop from 92 percent of demand in 1988 to 86 percent by the year 2010. The difference will mean close to a doubling of the percent of gas that is imported from nations like Canada, Mexico, Algeria, the Caribbean, Nigeria and Norway.

When Section 29 was enacted, no one could predict the gas market that existed when deregulation occurred and continues to exist today. Congress thought that a deregulated price would be sufficiently high to remove justification for the credit. Average gas prices rose in the early 1980s to as high as $7.83 per thousand cubic feet.

However, since 1985 gas prices have declined to their current level low levels, down to $1.50 per thousand cubic feet. Many producers find it difficult to make a profit at this price on conventional gas production, let alone tight sands production.

After 1987, very few production sites remained eligible for credit under the narrow definition of "tight sands production."

While the Section 29 credits have been available for almost 10 years, they have only been taken, generally, in the last few years. Recent advances in drilling and other technology have brought increased interest in these unconventional resources; unfortunately, in the closing years as the credits expire.

An extension of the credit will benefit consumers and the nation as a whole.

More orderly and environmentally responsible development of resources can occur if producers are not under a short timetable for completing hundreds of wells. If the credits expire, it is probable that much of the future development of these resources may not occur. In addition, natural gas is environmentally a more clean burning fuel.

Mr. Chairman, Members of the Committee, thank you for this opportunity to testify.

Prepared Statement of Craig G. Goodman

INTRODUCTION

Mr. Chairman, members of the Committee, my name is Craig G. Goodman, and I am honored to appear here today as the Tax and Legislative Counsel for The National Stripper Well Association.

The National Stripper Well Association is a trade organization which represents the operators of more than 450,000 crude oil wells, 74% of all wells operating in the United States today, and 3.8 billion barrels of proven recoverable domestic reserves. Operators of America's stripper wells are a true cross section of one of America's most capital intensive industries. Unlike many other industries, however, oil and gas production, particularly marginal production, is primarily a depleting capital industry.

Stripper wells are being permanently abandoned in the United States at a rate in excess of 17,000 wells per year. These wells and the domestic reserves behind these wells represents a significant national resource.

In the United States today, producers are actually taxed on the capital they invest to drill new wells. For many of these producers, the modem tax code virtually bars the return of this capital. In addition to the obvious legal implications of such provisions, taxes on invested capital force the premature abandonment of marginal wells and at the same time penalize efforts to replace the domestic production and reserves that are being lost.

In essence gentlemen, the U.S. tax code is now encouraging the depletion of America's resource base. We are, in effect, draining America first. At a time when clean air and tax fairness are of concern, there are no valid policy reasons to penalize the capital that is invested to find and develop new domestic reserves.

The National Stripper Well Association will identify the provisions of the tax code that impose direct taxation on drilling capital. We are also submitting a modest proposal with analysis to reduce this tax on capital consistent with both tax reform and our current budget deficits. Additionally, we would appreciate keeping the record in this hearing open so that we may submit additional qualitative and quantitative analysis of the regressive and anti-competitive impacts of these provisions.

BACKGROUND

In the price collapse/tax reform era of the last five years, U.S. production and reserve additions have declined dramatically, imports now have reached 50% of current consumption levels, and are increasing. From a peak of 8.9 million barrels a day just prior to the price collapse and the passage of The Tax Reform Act, U.S. production is now 7.2 million barrels per day, a full 1.7 million barrel per day loss. At $17 per barrel, this lost production alone costs the U.S. $10.5 billion a year. This is just the extra money we are now exporting to foreign producers to pay for our oil imports. Oil now represents a major portion of our trade deficit and as prices go up this percentage will increase dramatically.

Since 1985, virtually every major U.S. production statistic has declined by at least 50%. The total number of exploratory wells drilled per year has declined from. over 12,000 to near 6,000, development wells from near 60,000 to under 25,000, total footage drilled from over 300 million feet to under 150 million feet. And, a recent analysis presented at the last meeting of the National Stripper Well Association demonstrated clearly that these losses are only the beginning of a long term continuing decline in domestic production and reserve additions that currently has nc end in sight.

Taxes on Capital Invested to Maintain and Replace Domestic Production and Reserves are Regressive and Anti-Competitive

Many observers, particularly in Washington, would like to blame the entire problem on the OPEC price collapse. However, when prices increased from an average of $12 to over $15 per barrel from 1988 to 1989, U.S. production continued its decline by over 500,000 barrels per day. Clearly, if OPEC wanted to maximize it's long term profits and simultaneously wipe out the U.S. independent industry, it need only reduce it's prices to $5 per barrel for an extended period of time. Let the record reflect that we hope and pray this will not occur.

However, there is another, less obvious, reason that U.S. production and reserve additions have continued to decline, despite significant percentage increases in prices since the crash. Over 75% percent of U.S. independent producers are subject to multiple tax penalties on the capital they have invested or need to invest to replace existing production. Had oil prices stayed in the range that existed before tax reform, the penalties would not have had as large an impact. However, the price collapse actually caused these penalties to become operative and increased their impact.

It was bad enough that oil prices had collapsed from $30 to $10, but these tax penalties actually increased as prices, revenues and profitability declined. The National Stripper Well Association maintains that these penalties have been a major contributing factor to the decline of U.S. production and reserve additions in the post-tax reform period. The geology of the world has not changed dramatically since 1985, just the tax code.

Worse yet, imposing a tax on the capital used to maintain or replace lost production increases both the costs and risks of new drilling and lowers the after-tax return from these investments, particularly if prices, revenues or profitability decline. *Today in the United States. capital invested in new drilling by over 75% of the nation's independent producers will cost them more and return to them less than the exact same investment would to most for oil companies.*

Not only are these tax penalties regressive and anti-competitive, but they violate the basic premise of tax reform, namely tax neutrality. Today, the tax code and a producer's taxpaying position, rather than the underlying economics of an oil or gas project, can actually determine whether tax disadvantaged firms can replace their depleting reserves.

Tax reform never intended this result because tax reform never anticipated a 60% decline in oil prices. And it was this combination of regressive penalties together with the price collapse that causes these results.

The essence of the problem is that U.S. tax reform increased substantially the time within which capital invested in new drilling and reserve replacement can be recovered. Tax reform which started in 1969, has continuously eroded the ability of domestic producers to recover adequate capital to replace the thousands of wells that are plugged or become marginal producers. This erosion has taken the form of multiple "preferences" within the structure of the alternative minimum tax (AMT). Producers, primarily independent producers, now pay taxes on an ever-growing portion of the capital they invest in new drilling as well as their remaining capital assets.

RECOMMENDATIONS

The National Stripper Well Association strongly supports the industry's efforts to enact "plow-backs" and drilling investment credits as a way to reduce the regressive and anti-competitive impacts that reside within our tax code. However, we also believe that, at a very minimum, the existing penalties on marginal production and new drilling investments must be eliminated or reduced.

Therefore, we urge Congress to consider reducing the time it takes to recover the capital necessary to save and replace America's depleting resource base.

I. Stop the loss of America's marginal production by eliminating current restrictions on capital recovery from marginal production.

An area that needs immediate attention is the growing loss of marginal U.S. production. Once gone, this production and these known, proven reserves are lost, possibly forever. Lost also is the possibility to enhance this production and thereby maximize the known resource base of this country.

A well that produces an average of 2.6 barrels per day generates less than $20,000 a year in gross income before the high costs of operations, down time, and workovers are deducted. Allowing timely and sufficient capital recovery from these properties will not cost the government much in lost revenue because low volume wells do not pay much in taxes. However, it could encourage the operators of these wells to keep them producing until prices rise, or investments in new drilling or enhanced recovery become more competitive.

Senators Boren of Oklahoma, and Dole of Kansas and Congressman Clinger of Pennsylvania have proposed The Marginal Production Incentive Act (S. 1565 and H.R. 3437). Congressmen Archer, Andrews and Pickle of Texas have also proposed similar legislation. These bills contain cost-effective provisions that can help stop the loss of U.S. reserves and production.

These proposals would repeal current limitations on capital depletion for wells producing under 15 barrels of oil or 90 Mcf of gas per day. Repealing the depletion preference, the 1000-barrel-per-day limitation, the taxable income limitation and the transfer rule for low-volume properties plus increasing the net income limitation can stop the loss of this vast domestic resource. By allowing more efficient operation of wells that otherwise would be lost, these proposals can save billions of barrels of known proven domestic reserves for future recovery.

II. The U.S. Tax Code Must be Changed to Eliminate or Reduce the Tax on Capital Invested to Drill New Wells.

The Administration and a number of your colleagues are proposing both tax credits and, most importantly, a reduction or elimination of the two AMT preferences for expensing the costs of drilling new wells. The concept of treating the *capital* used to drill new wells as *income* for alternative minimum tax purposes is a relic from the time of OPEC embargoes and soaring oil prices. For over 75% of all independent producers, IRC §§ 56(g) and 57(a) have become a direct tax on the capital invested to drill new wells. Yet, without these new wells, independent producers are merely liquidating their assets.

IDC expensing has been in the code since the beginning of income taxation itself. Current tax law artificially forces 75% of the independent producers in this country to wait a minimum of 14 years to recover the capital invested in finding and developing a statistically average sized U.S. reservoir. For many of these producers, the tax code bars full recovery of their drilling capital. The National Stripper Well Association urges the return to full IDC expensing. However, at a very minimum, we are submitting a minor proposal that would shorten this waiting time to 11 years.

The technical provisions of the code and the language we propose are attached, together with a comprehensive analysis of the revenue and wealth effects of such a change. If this modest legislative proposal were added to S-1565 it would reduce the current penalties on new drilling by one-half and cost the Federal Treasury virtually no actual cash over the life of new projects brought on line.

Even considering the flaws in the revenue estimation process, this legislative proposal could inspire over 1300 new successful projects, over $4 billion in successful new investments, over 871 million barrels of new domestic reserves and approximately 200,000 barrels of new production per day before there would be a discounted revenue impact of $100 million per year. This is the amount allotted in the President's budget for AMT modifications. This represents a cost of approximately 11.5 cents per new barrel of reserves added.

CONCLUSION

The National Stripper Well Association urges reconsideration of antiquated, anticompetitive and regressive tax policies. Policies that are based on events that have no relevance to the post-tax reform era. U.S. tax policy must encourage capital formation in all areas of domestic petroleum extraction.

Full and timely recovery of the capital used to maintain and replace America's depleting resource base is the key to providing this tax policy. Capital formation in this vital industry can yield substantial benefits to all Americans. Each new project started because of this proposal adds over $13 million in new wealth to U.S. Society and over $2.7 million in new taxes to the U.S. Treasury.

The time to invest in America is now. Tax equity and efficiency require a new direction in U.S. energy tax policy. The National Stripper Well Association urges your leadership on these important issues. Thank you.

Legislative Proposal to Reduce the Impact of Internal Revenue Code Sections 56(g) and 57(a) on New U.S. Drilling Investments

PROPOSAL

Reduce the Amount of IDCs Subject to the Two Existing IDC Preferences by 50% and Increase the Net Income Limitation to 100%.

Existing statutory language with revisions in bold:

[Sec. 57 (a)(2)(B)(ii)]

Sec. 57. ITEMS OF TAX PREFERENCE.

(a) IN GENERAL RULE.—For purposes of this part, items of tax preference under this section are—

(2) INTANGIBLE DRILLING COSTS.—

(A) IN GENERAL—With respect to all oil, gas and geothermal properties of the taxpayer, the amount (if any) by which the amount of the excess intangible drilling costs arising in the taxable year is greater than [65] **100** percent of the net income of the taxpayer from oil, gas, and geothermal properties for the taxable year.

(B) EXCESS INTANGIBLE DRILLING COSTS.—For poses of subparagraph (A), the amount of the excess intangible drilling costs arising in the taxable year is the excess of—

(i) **one-half** of the intangible drilling and development costs paid or incurred in connection with oil, gas and geothermal wells (other than costs incurred in drilling a nonproductive well) allowable under section 263(c) or 291(b) for the taxable year, over

(ii) the amount that would have been allowable for the taxable year if such costs had been capitalized and straight line recovery of intangibles (as defined in subsection (b) had been used with respect to such costs.

[Sec. 56 (g)(4)(D)(i)]

Sec. 56. ADJUSTMENTS IN COMPUTING ALTERNATIVE MINIMUM TAXABLE INCOME

(g) ADJUSTMENTS BASED ON ADJUSTED CURRENT EARNINGS.

(4) ADJUSTMENTS.

(D) CERTAIN OTHER EARNINGS AND PROFIT ADJUSTMENTS.

(i) INTANGIBLE DRILLING COSTS. The adjustments provided in — section 312(n)(2)(A) shall apply in the case of **one half of the** amounts paid or incurred in taxable years beginning after December 31, 1989.

EXPLANATION OF CURRENT LAW

Currently, when computing alternative minimum tax liability, all producers of oil and gas must add back to regular taxable income a portion of the intangible drilling expenses incurred or paid in the taxable year. That portion for both individuals and corporations is the excess of current year IDC deductions over the sum of a hypothetical current year amortization of such costs and 65% of pre-IDC oil and gas taxable income. In addition to this preference, corporations are also subject to another preference item that is computed on the intangible drilling expenses incurred in a taxable year that exceed the amount that would otherwise be deductible if the corporation had amortized those expenses over a 5 year (60 month) period. For corporations, however, the amount of intangible drilling expenses that remain deductible in the current year after computing the first preference must then be used to compute the second preference.

REASONS FOR CHANGE

The impact and severity of the crude oil price collapse of 1986 was not anticipated within the current structure of the alternative minimum tax. Consequently, the two preferences for intangible drilling costs have had the unintended effect of increasing the relative tax burden for certain domestic producers as prices, revenues and profitability have declined over the last four years. The existence, magnitude and interplay of these two preferences have increased to an undesirable level both the costs and risks of exploring for and developing additional U.S. reserves for those taxpayers subject to one or both of these preferences.

While current budget constraints require that some preference on drilling investments remain, it is the belief of this Committee that the preexisting level of preferences on new drilling can be reduced consistent with the current year's budget resolution.

EXPLANATION OF CHANGE

The proposed changes to IRC Sections 56(g)(4)(D)(i) and 57(a)(2)(B)(ii) would reduce by one half, the amount of intangible drilling costs that must be amortized over either five or ten years by those corporate and individual taxpayers subject to the alternative minimum tax. Currently, the amount of intangible drilling costs which individual taxpayers cannot deduct in the current year as a result of IRC Section 57(a) are not available as a deduction in future years. Consequently, the proposed change would increase the income limitation against which these deductions are measured to 100% of net oil and gas income. Since corporations are subject to both IRC Sections 56(g)(4)(D)(i) and 57(a)(2)(B)(ii), this will also help to mitigate (but not eliminate) the current differences in the tax treatment of intangible drilling costs between corporate and non-corporate taxpayers.

Analysis of Proposal to Reduce the Impact of Internal Revenue Code Sections 56(g) and 57(a) on New U.S. Drilling Investments

INTRODUCTION

Set forth below is an analysis of the operation and effect of a proposal to reduce by one-half the amount of intangible drilling costs (IDCs) that are subject to the two alternative minimum tax (AMT) preferences contained in IRC §56(g) and IRC §57(a).

The impact on new drilling investments of IRC Sections 56(g) and 57(a) occurs "upfront" because the preferences substantially disallow deductions for IDCs in the year that the investment is made. This causes a "prepayment" of Federal taxes to be made which theoretically is repaid to the investor without interest by way of an AMT credit in future years. By limiting (or barring) the recovery of invested capital which creates AMT liability on the "front end" of new drilling investments, the two IDC preferences increase substantially both the costs and the risks attendant to such investments.

Additionally, if prices, revenues, or taxpayer profitability decline, or if the taxpayer otherwise remains subject to the AMT, the impact of these two preferences increases and the taxpayer may never receive the AMT credits provided by law. When this occurs, IRC Sections 56(g) and 57(a) become an unintended tax directly on either the invested capital itself or the remaining capital assets of the taxpayer.

SUMMARY

This proposal does improve project economics at a very modest real cost to the Federal Government. However, because this proposal does not reduce the actual cash payments that are made to the Federal Treasury over the life of a project, only the timing of those payments, it will not, by itself, render a statistically average U.S. drilling investment economic for an AMT taxpayer. Consequently, AMT taxpayers (primarily independent producers) will have to locate larger than average sized reservoirs to find acceptable economics even under this proposal.

Using base price forecasts, average U.S. reservoir statistics, and lower than average exploratory risks reported by the EIA in 1989, no actual undiscounted loss in revenues to the Treasury occurs over the life of an average project under this proposal. However, because the full financial impact of both preferences occurs in the year of the investment, the impact is $76,874 when discounted and inflated over the life of a project that becomes economic under this proposal using a 15% private and social discount rate. Additionally, since the economic impact of the AMT is basically regressive, the discounted, no-risk impact increases to $107,253 if prices decline to the EIA low price forecast.

It should be noted that the average size reservoir reported by EIA (640,000 barrels) is not economic to an AMT taxpayer under either EIA low or base price forecasts. Using EIA's base price forecasts, it would require a 670,000 barrel reservoir to become economic even under this proposal. The EIA base price forecast relied upon starts at a price of $16.33 per barrel of oil and $1.63 per Mcf of natural gas and rises to $94.24 per barrel and $9.42 per Mcf over the life of the project. This analysis also assumes a 75% risk of exploratory failure. The risk of failure for an average U.S. exploratory project is approximately 87%. Using this higher rate of exploratory risk, an AMT taxpayer must locate a 840,000 barrel reservoir to find acceptable economics under this proposal.

Using the EIA base price forecast and a 670,000 barrel reservoir size, the Federal Government would receive a total of $2,743,530 in new taxes per project under current law and the same under the proposal. Additionally, the total wealth added to U.S. society from this capital investment would be $13,386,944. This does not include reductions in the trade deficit or other indirect "multiplier" effects of the proposal. Obviously, neither the increase in Federal tax receipts of $2.74 million nor the $13.38 million in added wealth to society would occur unless changes to IRC §§56(g) and 57(a) are made to induce an AMT taxpayer to undertake this $3.2 million investment in new drilling. There is also no revenue impact if the investment is unsuccessful because the proposal does not change the treatment of dry-hole costs.

Since both IDC preferences impose the full AMT tax burden on the investment before it generates sufficient cash flow to actually owe taxes, the return of capital to the investor may not occur under a number of different scenarios. These scenarios include low or declining prices, lower revenues from oil and gas operations, higher drilling costs or a combination of the three. If the investor stays only marginally profitable, loses money or remains an AMT taxpayer for any other reason, the tax on drilling capital embedded in the two IDC preferences may never be recovered fully by the taxpayer.

Under the EIA's base price forecast and using average reservoir statistics, the Government does not finally repay the "up-front" AMT payment for 14 years or longer under current law, and 11 years under the proposal. If larger than average reservoir statistics (670,000 barrels) and the EIA base price forecast are used, this time is shortened from 13 to 11 years.

There are several ways to measure the revenue impact of this proposal. Treasury receipts can be measured under current law compared to what they would be under the proposal on an "expected", "undiscounted" or "discounted" basis. The "actual" undiscounted cash flows and the "expected" values of the investment and the revenue streams demonstrate "real life" impacts as these are the measures utilized when drilling investments are made. Discounting alone assumes, in all cases, that the drilling investment will be successful and that producers do not take geological risks. Consequently, these measures exaggerate the revenue impact of each project. Observations using the discounted, undiscounted and expected revenue impacts of this proposal are set forth below.

I. The Actual "Undiscounted" Revenue Impact of the Proposal.

The IDC preference(s) and the AMT generally is considered merely a "cash flow adjustment" or a "timing mechanism" which advances tax collections before the return of capital. As a result, it is not surprising that the undiscounted revenue impact of a project that becomes economic because of this proposal is zero. As stated above, using the EIA base price forecast and average reservoir statistics, Federal tax receipts would increase by $2,511,810 under current law and the same amount under the proposal. A 670,000 barrel reservoir which becomes economic under this proposal would generate $2,743,530 in new Federal tax receipts if the impact of IRC §§ 56(g) and 57(a) were reduced by one half. Since this proposal is targeted to new and successful drilling investments only, each new project that becomes economic would add over 200 barrels per day of production without any actual cash effect to the Treasury over the life of the project.

It should also be observed that each project that becomes economic under this proposal causes a substantial increase in wealth to occur to U.S. society. Each $3.2 million, 670,000 barrel project creates $13,386,944 million in "actual" undiscounted social wealth to occur using the EIA base price forecast. This wealth flows to State and Federal Governments, the taxpayer, the landowner and others. Additional social wealth effects created by this activity include payments to contractors, multiplier effects and trade impacts. However, no attempt has been made to quantify these wealth effects.

The substantial increases in both tax receipts and wealth attendant to reducing the impact of IRC §§ 56(g) and 57(a) occur because of the structure of the AMT. The incidence of the AMT occurs on the capital investment itself, rather than the income generated by the investment. The structure of the AMT and both IDC preferences would theoretically be improper if the law did not also provide an AMT credit to allow a taxpayer to recover the capital based portion of the tax in later years. The theoretical propriety of the AMT and the IDC preferences rests on the assumption that a taxpayer becomes profitable enough to one day owe regular income taxes so that the return of capital through the AMT credit occurs. If this does not occur, the AMT payments that are never creditable become a direct tax on capital instead of income.

II. Discounted, Risk-Weighted "Expected" Revenue Impact of the Proposal

The "expected" value of the revenue impact of this proposal discounts the cash flows to the investor, the Treasury and society by both a social discount rate plus the geological risk of the investment. An investor looks at the "expected" after tax value of his investment to determine whether he will recover the cost of his funds and make a profit after the geological risk of failure is considered.

The expected return of and return on capital as well as the expected revenue streams generated by that capital are the most reliable indication of what will occur in "real life." It should be noted, that to the extent that U.S. society, the Treasury, or the revenue estimation process are indifferent to an investor's "expected" return of capital, substantial wealth and competitive opportunities are missed.

The "expected" revenue impact of reducing by one-half the economic impact of IRC §§ 56(g) and 57(a) is only $19,219 for each 670,000 barrel project that becomes economic as a result of this proposal. This impact increases to $26,813 if prices decline to the EIA low price forecast. At $19,219 per project, over 5,000 new projects could be started before $100 million in "expected" revenue impact would occur.

What is most interesting about using "expected" values, is that relatively small increases in the after-tax expected value of the investment to the investor causes substantial increases in both expected wealth and expected tax receipts. For example, using the EIA base price forecast, a 75% exploratory risk, and a 670,000 barrel reservoir size, an investor can "expect" a *loss* of $1,866 under current law. However, under the proposal, the same investment yields an "expected" *profit* of $17,353.

To make this project economic, Federal tax receipts need only be reduced by $19,219 on an expected basis while no actual cash would be lost on an undiscounted basis. Likewise, this minor "expected" revenue impact can be expected to add approximately $610,282 in new wealth to U.S. society

It should be noted that regular Federal income tax payments over the life of an average sized U.S. project or a 670,000 barrel project are unchanged by this proposal. Only the up-front prepayment of Federal taxes on invested drilling capital represented by the two IDC preferences has been reduced.

III. Discounted Revenue Impact of the Proposal

Due to the fact that the full economic impact of both IDC preferences occurs in the year that capital is invested in new drilling and no geological risks are assumed, the discounted and inflated value of the revenue impact exceeds its "actual" cash effect to the Treasury and U.S. society.

Using the EIA's base price forecast and a 670,000 barrel reservoir size, the discounted revenue impact is $76,874 per new successful project assuming no geological risks are involved. Using a 15% social discount rate, the Treasury would collect $804,405 per 670,000 barrel project if the investment was made under current law and $727,531 under the proposal.

However, capital investment in new drilling would not be profitable using either the EIA low or base price forecasts and EIA statistically average reservoir sizes, if IRC Sections 56(g) or 57(a) continue in effect. The added $727,531 in tax receipts is realized only using the EIA base price forecasts, a 670,000 barrel reservoir size (and/or lower than average exploratory risk assumptions) and the proposed reduction in the IDC preferences.

It should also be noted that the discounted, no-risk impact of $76,874 per project that becomes economic under this proposal not only increases Federal tax receipts by $727,531 per project, but it also increases wealth to U.S society by $2,950,128 per project using a 15% social discount rate.

Using this higher measure of the revenue impact, 1300 successful new projects could be started, an estimated 871 million barrels of new reserves, and approximately 200,000 barrels of new production per day could be added before there would be a $100 million revenue impact. Because 670,000 barrels or larger reservoirs become economic with this proposal, over $4 billion in successful new investments, primarily by independent producers, would have to occur before the Treasury would lose $100 million using a 15% social discount rate and no risk assumptions. This represents a cost to the Government of approximately 11.5 cents per new barrel of reserves added. The 1300 new projects also would increase Treasury receipts on a discounted basis by approximately a billion dollars over current law, and add over $3.8 billion in discounted new wealth to U.S. society.

If a lower social discount rate is used to measure the revenue impact of this proposal, the return to the Treasury in the form of increased tax receipts, the increase in wealth to society and the amount of new capital that could be invested in finding and producing new domestic reserves would all increase before the discounted impact of this proposal reaches $100 million.

INDEPENDENT AMT TAXPAYER USING EIA BASE PRICE FORECASTS AND AVERAGE RESERVOIR STATISTICS- UNDER CURRENT LAW

	A	B	C	D	E	F	G	H	I	J
169	Dry Hole Rate	75.00%								
170	Expected Project Worth									
171	*Expected Social Worth*	$538,249								
172	*Expected Company Worth*	($44,393)								
173										
174	Distribution of Total Discounted Project Worth									
175		Discounted /No Geological Risk Case			Expected Worth			Actual Undiscounted Cash Flows		
176		$	Percent			Percent			Dollars	Percentage
177	*Company Worth*	*$542,670*	*20.39%*		*($44,393)*	*-8.25%*		*Company*	*$5,753,150*	*46.29%*
178	Bonus	$130,435	4.90%		$130,435	24.23%		Bonus	$150,000	1.21%
179	Net Royalty	$934,493	35.10%		$233,623	43.40%		Net Royalty	$3,017,609	24.28%
180	Severance	$308,819	11.60%		$77,205	14.34%		Severance	$997,220	8.02%
181	*Net Federal*	*$745,580*	*28.01%*		*$141,380*	*26.27%*		*Gross Federal*	*$2,511,810*	*20.21%*
182	*Total Wealth Added to Society*	*$2,661,998*	*100.00%*		*$538,249*	*100.00%*		*Total Wealth*	*$12,429,790*	*100.00%*

INDEPENDENT AMT TAXPAYER USING EIA BASE PRICE FORECASTS AND AVERAGE RESERVOIR STATISTICS - ALSO USING PROPOSED REDUCTION IN IDC PREFERENCES

	A	B	C	D	E	F	G	H	I	J
169	Dry Hole Rate	75.00%								
170	Expected Project Worth									
171	*Expected Social Worth*	$538,249								
172	*Expected Company Worth*	($23,958)								
173										
174	Distribution of Total Discounted Project Worth									
175		Discounted /No Geological Risk Case			Expected Worth			Actual Undiscounted Cash Flows		
176		$	Percent			Percent			Dollars	Percentage
177	*Company Worth*	*$624,412*	*23.46%*		*($23,958)*	*-4.45%*		*Company*	*$5,753,150*	*46.29%*
178	Bonus	$130,435	4.90%		$130,435	24.23%		Bonus	$150,000	1.21%
179	Net Royalty	$934,493	35.10%		$233,623	43.40%		Net Royalty	$3,017,609	24.28%
180	Severance	$308,819	11.60%		$77,205	14.34%		Severance	$997,220	8.02%
181	*Net Federal*	*$663,839*	*24.94%*		*$120,945*	*22.47%*		*Gross Federal*	*$2,511,810*	*20.21%*
182	*Total Wealth Added to Society*	*$2,661,998*	*100.00%*		*$538,249*	*100.00%*		*Total Wealth*	*$12,429,790*	*100.00%*

INDEPENDENT AMT TAXPAYER USING EIA BASE PRICE FORECASTS AND A 670,000 BARREL RESERVOIR SIZE- UNDER CURRENT LAW

	A	B	C	D	E	F	G	H	I	J
169	Dry Hole Rate	75.00%								
170	Expected Project Worth									
171	*Expected Social Worth*	$610,282								
172	*Expected Company Worth*	($1,866)								
173										
174	Distribution of Total Discounted Project Worth									
175		Discounted /No Geological Risk Case			Expected Worth			Actual Undiscounted Cash Flows		
176		$	Percent			Percent			Dollars	Percentage
177	*Company Worth*	*$712,779*	*24.16%*		*($1,866)*	*-0.31%*		*Company*	*$6,264,[illegible]*	*46.79%*
178	Bonus	$130,435	4.42%		$130,435	21.37%		Bonus	$150,000	1.12%
179	Net Royalty	$978,986	33.18%		$244,747	40.10%		Net Royalty	$3,178,780	23.75%
180	Severance	$323,523	10.97%		$80,881	13.25%		Severance	$1,050,482	7.85%
181	*Net Federal*	*$804,405*	*27.27%*		*$156,086*	*25.58%*		*Gross Federal*	*$2,743,530*	*20.49%*
182	*Total Wealth Added to Society*	*$2,950,128*	*100.00%*		*$610,282*	*100.00%*		*Total Wealth*	*$13,386,944*	*100.00%*

INDEPENDENT AMT TAXPAYER USING EIA BASE PRICE FORECASTS AND A 670,000 BARREL RESERVOIR SIZE - ALSO USING PROPOSED REDUCTION IN IDC PREFERENCES

	A	B	C	D	E	F	G	H	I	J
169	Dry Hole Rate	75.00%								
170	Expected Project Worth									
171	*Expected Social Worth*	$610,282								
172	*Expected Company Worth*	$17,352								
173										
174	Distribution of Total Discounted Project Worth									
175		Discounted /No Geological Risk Case			Expected Worth			Actual Undiscounted Cash Flows		
176		$	Percent			Percent			Dollars	Percentage
177	*Company Worth*	*$789,653*	*26.77%*		*$17,352*	*2.84%*		*Company*	*$6,264,153*	*46.79%*
178	Bonus	$130,435	4.42%		$130,435	21.37%		Bonus	$150,000	1.12%
179	Net Royalty	$978,986	33.18%		$244,747	40.10%		Net Royalty	$3,178,780	23.75%
180	Severance	$323,523	10.97%		$80,881	13.25%		Severance	$1,050,482	7.85%
181	*Net Federal*	*$727,531*	*24.66%*		*$136,867*	*22.43%*		*Gross Federal*	*$2,743,530*	*20.49%*
182	*Total Wealth Added to Society*	*$2,950,128*	*100.00%*		*$610,282*	*100.00%*		*Total Wealth*	*$13,386,944*	*100.00%*

U.S. Petroleum Income Taxation 1890-1990

An Historical and Quantitative Analysis of the Economic Burdens on the Extraction of Petroleum Resources in the United States

by

Craig G. Goodman, Esq.*

* Craig G. Goodman is Vice President, Governmental Affairs for Mitchell Energy Corporation in The Woodlands, Texas. Between October 1987 and November 1989, Mr. Goodman served as Director of Oil, Economic, and Energy Tax Policy, and then Director of the Office of Energy Tax Policy within the U.S. Department of Energy. Prior to government service, Mr. Goodman was Senior Counsel and Director of Energy and Tax Policy for the Independent Petroleum Association of America. Mr. Goodman is a member of the Bars of the States of Texas, Florida, and Washington, D.C. and is admitted to practice before the United States Supreme Court.

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Foreword

This manuscript went to print as U.S. troops landed in Saudi Arabia in response to the Iraqi invasion of Kuwait, and the world crude oil and financial markets have started to reflect the expected price increases of future crude oil supplies. The full economic effects of the August 2, 1990 takeover of Kuwait and its aftermath cannot be predicted with certainty at this writing. Crude oil inventories are relatively high; post-invasion crude oil supplies and the Strategic Petroleum Reserve draw-down capabilities are significant.

These recent events underscore the significance of the historical changes that have occurred in the definition of U.S. "taxable income" and the multiple limitations that have been placed on the ability of U.S. producers to recover the capital and non-capital costs necessary to replace depleting U.S. reserves. This analysis of U.S. petroleum income taxation, and particularly the changes that have occurred in the timing of cost recoveries from investments to replace domestic reserves, helps to explain the dramatic increase in the post-tax-reform U.S. reliance on imported crude oil.

In the four years since the 1986 collapse in world oil prices, crude oil production in the United States has declined by over one and a half million barrels per day despite interim price increases of over one hundred percent. U.S. exploratory and development efforts, measured by the drilling rig count, feet drilled, reserves replaced in the United States, and seismic crew activity, remain near record lows. In 1988, the U.S. spent $38 billion on imported crude oil. By 1995 this amount could increase to over $100 billion.

There are two major factors which determine the level of U.S. crude oil production: the world price of crude oil and the "expected" after-tax return on U.S. petroleum extraction investments. Analysis of cartel pricing policies or attempts by the United States to control the price of crude oil on either a unilateral or multilateral basis is beyond the scope of this analysis. Instead, this analysis is intended to provide context and understanding of the relative competitiveness of U.S. petroleum extraction investments.

To determine whether an investment to replace depleting U.S. reserves is a competitive use of capital, a U.S. investor must simultaneously compute the economic effects of geological risk, drilling and operating costs, the time value of money and the timing of cost recoveries, the return from lower risk investments, and the competitive advantages of foreign petroleum tax and fiscal systems compared to the U.S. system.

Of all the factors that influence investments to maintain and replace depleting U.S. petroleum resources, the one that the Federal Government has the most control over is the structure, operation and the relative competitiveness of the Federal petroleum income tax system. The structure, operation and relative competitiveness of the U.S. system has had a significant impact on the "expected" after-tax return on U.S. extraction investments and, therefore, the level of domestic crude oil production and reserve replacements.

Overview and Conclusions

During the period between December 1985 and August 1990, after the concurrent collapse of world oil prices and the passage of the U.S. Tax Reform Act of 1986, an issue developed as to whether the U.S. system of income taxation imposes a direct tax on the capital invested to maintain and replace U.S. petroleum production and reserves rather than on the "income" stream produced from those investments. By analyzing the historical development of U.S. petroleum income tax law and policy, and checking the results against sophisticated quantitative and comparative analysis, the author believes there is substantial evidence that more than an insignificant portion of the financial burden of the U.S. system of income taxation falls directly on the capital invested in depletable petroleum resources in the United States. These findings pose significant implications for U.S. energy and tax policy, U.S. national security, U.S. trade, the balance of payments, and the long-term economic welfare of the United States.

The historical analysis demonstrates how the U.S. tax reform movement changed dramatically and adversely the time within which investments in domestic petroleum extraction are recovered. In so doing, the various tax reform acts between 1969 and 1986 have changed the focus and economic impact of U.S. income taxation for a significant portion of U.S. productive petroleum assets, notably for those producers whose income is based primarily on domestic wellhead revenues.

The inception and expansion of the alternative U.S. system of income taxation has increased the tax burden that results from capital and non-capital investments in new drilling and reserve replacement in the United States. While early alternative minimum tax policy affecting petroleum was intended as a penalty for OPEC price spikes of the 1970s, its expansion in 1986 has caused substantial dysfunction in its operation during the post-collapse oil price regime.

The alternative system of petroleum taxation in the post-collapse/tax reform period has produced impacts that are regressive as a function of lower crude oil prices, lower net income from oil and gas operations or lower corporate profitability and has produced anticompetitive impacts among taxpayers undertaking identical drilling investments.

The quantitative analysis in Section Three demonstrates clearly the numerous regressive and anticompetitive impacts among firms and taxpayers, particularly as crude oil prices, revenues and/or profitability decline. First, the percentage of a firm's net income taken by the U.S. tax and fiscal system increases, both absolutely and relative to firms in more profitable taxpaying positions. Second, this regressive feature causes the after-tax return from U.S. extraction investments to decline at the same time it causes the after-tax cost of such investments to increase, particularly for less profitable firms. Third, firms in relatively similar competitive positions within the same industry but in different taxpaying positions have substantially different "expected" after-tax returns from identical drilling investments. Last, the U.S. tax and fiscal system generally and, the alternative minimum tax system specifically discourages risk taking. Thus, the system distorts economic decision making, resulting in potentially significant losses in wealth to U.S. society.

Since U.S. producers that drill the largest percentage of domestic wells have fallen into both the lower income and the less favorable tax positions, the implications for national energy, tax, trade and security policies are significant.

Additionally, the author has found that certain arguments used to blur the real economic distinctions between *high risk depleting finite capital asset industries* and *low-risk depreciating capital asset industries* are both misleading in an historical context and inaccurate when analyzed using sophisticated microeconomic quantitative and comparative analysis.

The current U.S. definition of "taxable income", which now includes drilling investments and asset depletion, represents a major departure from the historical structure of the U.S. income tax system as well as from its constitutional underpinnings. Moreover, quantitative and comparative analysis suggests strongly that the changes made to the U.S. petroleum income tax code over the last twenty years may have actually encouraged *depleting America first.*

U.S. Petroleum Income Taxation 1890-1990

Executive Summary

Federal income taxes are relatively new compared to other forms of taxation. The Constitution granted broad powers to the Federal Government to levy *indirect* taxes—*e.g.*, duties and excise taxes—requiring only that they be imposed uniformly throughout the Nation. Until the 20th century, indirect taxes were the major source of government funding. The government's power to impose *direct* taxes, such as *ad valorem*, severance, and income taxes, however, was more limited. The Constitution allowed the Federal Government to impose a direct tax on property only if the tax was apportioned among the states according to population. Each state would then tax property within its boundaries by whatever means it chose and remit its assessment to the Federal Government.

In 1862, Congress passed an income tax to finance the Civil War, but repealed it before it was challenged on constitutional grounds. In 1894, the Federal Government again sought to impose a direct tax on income. The U.S. Supreme Court, however, reasoning that a tax on the income generated from property was equivalent to a tax on the property itself, held that the constitutional rule of apportionment extended to the taxation of income.

In response to this decision and to satisfy a growing need for tax revenues, the 16th Amendment to the Constitution was ratified in 1913, granting Congress the power "*to lay and collect taxes on income from whatever source derived.*" Congress immediately exercised this new power and enacted the first constitutional income tax law. The nominal tax rate for both individuals and corporations was one percent.

The tax rate, however, is only one element in determining tax liability. Of equal or greater importance is the definition of *taxable income*. Taxable income generally has been defined as the gross income from all sources, less the ordinary and necessary costs of doing business, minus an allowance for the recovery of the capital assets consumed in producing that income. Additional allowances have been provided for gains or losses arising from the sale of capital assets. Normally, deductions for losses that are not fully usable in one year become either capital losses or net operating losses and, subject to certain limitations, are deductible over subsequent tax years.

To remain viable, a business must recover the capital assets it uses in the production of income. Accordingly, Congress has avoided imposing *income* taxes on *capital*. Federal tax law, therefore, recognizes the value of capital assets consumed in the operation of a business as one of the costs of doing business and provides allowances and deductions for the recovery of such capital.

The capital and non-capital cost recovery provisions affecting petroleum extraction are different from comparable provisions in other industries. When a business' assets are plant and equipment, the consumption of capital is called *depreciation*. When the assets are exhaustible natural resources, such as oil and gas, the consumption of capital is called *depletion*.

The primary capital assets of a natural resource extraction firm are finite deposits of an exhaustible resource. An oil producing firm is continually liquidating its principal assets in order to generate sufficient revenues to continue operating. Unlike a business that collects rent from real estate, an oil producer sells off its capital assets over time so that when these assets are depleted, there is virtually no capital left. Also, unlike ordinary plant and equipment, deposits of natural resources—particularly oil and gas—are not easily replaced. They are increasingly difficult to locate, costly to extract, and involve substantial financial risk for investors.

During the first third of this century, the U.S. was a low-cost, high-volume producer of crude oil. Relatively quick capital and non-capital cost recoveries encouraged rapid reinvestment to replace the oil reserves being extracted. Starting in the 1930s, however, it became increasingly difficult to locate productive new oil fields in the United States as dry hole rates increased dramatically. The size of discoveries also was declining. Early in the 20th century, a deposit with less than 20 million barrels of crude oil was not a major discovery. Today, a deposit of one million barrels is a major find.

Cost recovery provisions affecting domestic petroleum extraction include percentage and cost depletion, depreciation, and deductions for recovery of intangible drilling costs (IDCs) and geological and geophysical (G&G) expenses. IDCs include drilling-related expenses: *e.g.*, labor, fuel and other such items generally having no salvage value. G&G expenses involve acquisition of information used to determine the existence or location of hydrocarbon resources. There also are significant limitations on the use of net operating losses, passive losses, depletion and tax credits. These provisions generally serve to define the portion of total sales revenues to be treated as *"taxable income"* when computing regular federal income tax liability.

As the tax code evolved, allowances for capital and non-capital cost recovery changed frequently. Consequently, so has the portion of oil and gas sales revenues that has been characterized as *"taxable income"*. The federal income tax code at first allowed a small, and then briefly a larger, allowance for depletion. Thereafter, the depletion allowance and deductions for IDCs and G&G costs all declined. Since 1918, the effect of virtually every major change in U.S. petroleum income taxation has increased the portion of oil and gas sales revenues characterized as "taxable income" and decreased the portion that can be retained as capital or non-capital cost recovery.

The *alternative minimum income tax* system created a new definition of *"taxable income"*. This new definition of *income* often requires the prepayment of federal income taxes based on the level of current capital and non-capital investments rather than on the true economic income associated with that investment. In so doing, it has increased considerably the costs and the risks associated with domestic extraction investments and thereby lowered the after-tax rate of return from these investments.

Historically, the regular income tax system has provided for capital cost recoveries for natural resource extraction, particularly oil and gas, as the *greater* of the cost or value of the depletable resource. Under the alternative definition of *taxable income*, deductions for many capital and non-capital costs, such as depletion, depreciation, and IDCs, are limited severely or unavailable in a real economic sense. Consequently, a company or individual exploring for oil and gas in the United States today may sustain real economic losses defined under traditional income tax principles, yet incur alternative minimum income tax liability.

U.S. Petroleum Income Taxation 1890-1990

Introduction

Evolution of the U.S. system of petroleum income taxation can be divided into three historical periods. The creation and initial development of the U.S. income tax system and the origins of energy tax law and policy occurred during the period between 1894 and 1926. From 1926 to 1969 there was relatively little change. During this period the concept of *percentage depletion* was adopted and expanded as a vehicle for recovering the capital depletion associated with natural resources. Also certain limitations were placed on the recovery of geological and geophysical expenses. The most recent period, beginning in 1969, is marked by the creation and expansion of an alternative system of U.S. income taxation plus new and significant limitations placed on the recovery of capital and non-capital costs associated with U.S. petroleum extraction. The focus of this analysis is on the marked contrast between the post-tax reform era and the entire prior history of U.S. petroleum income taxation.

Creation of the U.S. Income Tax System (1894-1926)

Distinction between direct and indirect taxation

The modern U.S. income tax system is the result of a struggle over federal efforts to impose taxes directly on the property and incomes of U.S. citizens. Article 1, Section 8 of the Constitution granted Congress the broad power "*to lay and collect Taxes, Duties, Imposts and Excises.*" However, until ratification of the 16th Amendment, this power was limited by Article 1, Section 2, which specified that "*direct taxes shall be apportioned among the several states...according to their respective numbers.*"

Early constitutional debates and case law recognized the need for the Federal Government to have the power to raise revenues to finance its operation. But the framers of the Constitution placed safeguards on the exercise of this power by requiring that *direct* taxes be apportioned among the states and *indirect* taxes be imposed uniformly throughout the nation. The distinction between direct and indirect taxes was the subject of much debate. Generally, direct taxes are imposed on the *ownership* of property, whereas, indirect taxes are imposed on the *use* or *consumption* of property.[1]

The Federal Government was not prohibited from taxing property, but it was required to do so only in accordance with the constitutional rule of apportionment.

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1 An example of a direct tax is a severance tax, whereas an indirect tax would be a sales or franchise tax. The difference is somewhat more difficult to determine when the tax takes the form of an excise tax computed on the income of a corporation, such as the one passed in 1909. The distinction set forth above is the one posited by the Supreme Court in the landmark case of Hylton v. United States, 3 Dall. 171 (1796).

The rule required that the value of a direct tax on the ownership of land or other property was to be divided among the states according to a population census. Each state then would pay its assessed amount, collecting the tax from its citizens in accordance with its own local system of taxation.

The framers of the Constitution intended that direct taxation of property by the Federal Government should be a difficult procedure because they believed that taxation should be representative in a manner similar to that by which Congressional districts are apportioned.[2] Moreover, the framers believed that the government would be able to raise sufficient revenues to meet its needs through indirect levies, such as excise taxes and import fees. Unlike the Federal Government, the state governments had inherent sovereign powers to levy taxes directly on incomes and property.

Constitutional challenge over income taxation

Since *income taxes* were not mentioned in the Constitution, there was considerable controversy as to whether an income tax was a direct tax requiring apportionment or an indirect tax which simply required uniform application. The controversy was not resolved until 1895 in the landmark case of Pollock v. Farmers' Loan & Trust Co.[3] and the subsequent ratification of the 16th Amendment to the Constitution in 1913.

In *The Income Tax Act of 1894*, Congress imposed a two percent annual tax on the *gains, profits, and income* received by U.S. citizens. This tax was immediately challenged on constitutional grounds for its failure to meet the apportionment rule. In the Pollock case, the Supreme Court held that a tax on income or dividends derived from any real or personal property, including the bonds and capital stock of corporations, was equivalent to a direct tax on the capital or property itself and, therefore, subject to the apportionment rule.[4] The Federal Government's power to impose uniform excise taxes on both property and income remained unaffected.

The origins of U.S. energy tax policy

The Supreme Court's interpretation in the Pollock case of the limits on the Federal Government's power to impose income taxes led to three major developments:

- Congress enacted *The Corporation Tax Act of 1909;*
- the 16th Amendment to the U.S. Constitution was ratified in 1913; and
- the first constitutionally permissible federal income tax was imposed one week later.

2

"*They retained this security by providing that direct taxation and representation in the lower house of Congress should be adjusted on the same measure.*" Footnote 3 *supra* at pages 621-622.

3

158 U.S. 601 (1895).

4

An explanation of the Court's logic which also contains an earlier reference to the relationship between income, capital and property is contained in the following quote:

"*A tax upon one's whole income is a tax upon the annual receipts from his whole property, and as such falls within the same class as a tax upon that property, and is a direct tax, in the meaning of the Constitution....This principle which seems critically correct, would exempt as well the income as the capital of the property. It protects the use, as effectually as the thing. What, in fact, is property, but a fiction, without the beneficial use of it? In many cases, indeed, the income or annuity is the property itself.*" (emphasis added) *Ibid.* at pg. 625.

These developments, along with passage of *The Revenue Act of 1918* and the Supreme Court's interpretation of each of these measures, formed the basis of early U.S. energy tax policy. The legislative history and court cases surrounding these events made it clear that different income tax provisions were necessary for depletable natural resource extraction industries, primarily because these industries rely on revenues generated by the liquidation of their primary capita assets to continue operations.

Historically, however, the depletable nature of these assets has presented Congress and the courts with difficulty in distinguishing the portion of sales revenues that should be treated as *income*, and thus subject to *income* taxes, and the portion of revenues that are a *return of capital* and, therefore, not subject to taxation.[5]

This difficulty was first underscored by the Supreme Court in the landmark case of Stratton's Independence, Ltd. v. Howbert.[6] This case arose from a provision in *The Corporation Tax Act of 1909* that imposed an excise tax on the gross receipts of all corporations, subject to certain deductions and losses, including depreciation. Since this Act was passed before ratification of the 16th Amendment and after the Pollock case, Congress was careful not to levy a direct tax on property or capital, *per se*, but instead imposed a uniform excise tax on the privilege of doing business in the corporate form.

A distinction arose between the taxation of natural resource extraction and other business activities because of the provision in this Act for a deduction for the "depreciation of property". Both the company and the Treasury Department interpreted this language as providing a deduction "*...for depreciation arising from the exhaustion of deposits of ore, mineral, etc....*" [7]

In the Stratton case, the Supreme Court upheld Congress' authority to impose an excise tax on the conduct of business in the corporate form. But the Court refused to extend the statutory deduction for depreciation of property to the depletion of natural resources.[8] In effect, as long as Congress was inclined to impose an excise tax on corporate receipts, the Constitution required it to do so uniformly on all corporations throughout the United States. Since the central issue was an excise tax, the Court did not address whether or to what extent oil and gas sales revenues represent *income* or a *return of capital*, as

5
The *return of capital* doctrine was enunciated by the Supreme Court in the case of Burnet v. Logan, 283 U.S. 404 (1931), in part, as follows:

"In order to determine whether there has been gain or loss, [income] and the amount of the gain, if any, we must withdraw from the gross proceeds an amount sufficient to restore the capital value that existed at the commencement of the period under consideration."

6
231 U.S. 399 (1913). See also footnote 7 *supra*.

7
T.D.1675, 14 Treas. Dec. Int. Rev. 16 (1911). See also the stipulated facts on appeal in the Stratton case.

8
The Court held the mining company subject to the operation of the excise tax. However, both parties agreed and stipulated that the "actual depletion" of the ore body was equal to the value of the ore removed and sold in that year. Consequently, the Supreme Court refused to address the issue as to the nature and definition of "*income*" as well as the adequacy and proper computation of resource depletion by stating as follows: "*We are not at this time concerned with this vexed question,...where the question is—What is the income derived from the business?—and the incidental question—What is the reasonable depreciation, if any, of the mining property?*" 231 U.S. 399, 422 (1913).

those terms were used for income tax purposes.[9]

It was significant, however, that the Supreme Court recognized that natural resource extraction firms rely primarily on the sale of depletable or "wasting assets" to generate sufficient revenues to continue the operations of the business. The Stratton case is generally considered the beginning of modern U.S. energy tax law and the impetus for subsequent changes in U.S. energy tax policy.

The 16th Amendment

On February 25, 1913, the 16th Amendment to the U.S. Constitution was ratified. It granted the Federal Government the power "*...to lay and collect taxes on incomes, from whatever source derived, without apportionment among the several States.*"

Within a week of ratification, the Congress passed *The Tariff Act of 1913,* which imposed a tax on both personal and corporate income. The nominal tax rate for both individuals and corporations was set at one percent. Congress included in this Act the first *depletion allowance,* which permitted natural resource producers to deduct: "*...a reasonable allowance for...wear and tear of property arising out of its use or employment in business, not to exceed, in the case of mines, 5 per centum of the gross value of the mine output for the year for which the computation is made...*"

The five percent depletion allowance led to a new round of Supreme Court challenges by natural resource firms.[10] This time, however, the contention was that the five percent allowance for the depletion of the ore body was inadequate.[11] The Court used the pre-16th Amendment uniformity logic it applied to an excise tax on gross receipts in the Stratton case to uphold Congress' power to impose a post-16th Amendment tax on "*income from whatever source derived.*" By failing to distinguish between an indirect excise tax on "*gross receipts*" and a direct tax on "*income*", this decision blurred the legal and economic distinctions between *income* and *the return of capital* from investments in depleting finite resources.

During the resolution of these early cases and throughout the first 70 years of the 20th century, the Supreme Court consistently recognized, however, that revenues from the sale of natural resources are not all *income,* as that term is used in the tax laws. Explaining the nature and intent of the depletion allowance, the Court emphasized that: "*...[depletion] is permitted in recognition of the fact that the mineral deposits are wasting assets and is intended as compensation to the owner for the part used up in production.*"[12]

Moreover, the Supreme Court made it clear that "*[The depletion] exclusion is designed*

9
Ibid. at page 417.

10
See: Stanton v. Baltic Mining Company, 240 U.S. 103 (1915). See also: United States v. Ludey, 274 U.S. 295, 302 (1927); Helvering v. Elbe Oil Land Development Co., 303 U.S. 372, 375(1938); Anderson v. Helvering, 310 U.S. 404, 408 (1940); Kirby Petroleum Co. v. Commissioner, 326 U.S. 599, 603 (1946); Parsons v. Smith, 359 U.S. 215, 220 (1959).

11
This contention can better be understood if illustrated. Assume that a mining corporation pays $1 million for a mine containing 1 million tons of recoverable ore. Assume further that in any given year 100,000 tons are mined and sold for $300,000. Under the 1913 law, the taxpayer could deduct up to 5 percent of the sales price, or $15,000, for depletion, and the balance (less other expenses) would be taxable income. But the 100,000 tons of ore mined had an actual capital cost of $100,000.

12
Helvering v. Bankline Oil Co., 303 U.S. 363, 366 (1938).

to permit a recoupment of the owner's capital investment in the minerals so that when the minerals are exhausted, the owner's capital is unimpaired." [13]

The depletion allowance has consistently stood as explicit recognition by Congress and the courts that a portion of the sales revenues generated from petroleum extraction is to be treated properly as a *return of capital* from the sale of a firm's primary capital asset. While the exact valuation of that portion has changed from time to time, the principle has remained constant.

The primary capital assets of a natural resource extraction firm typically are finite deposits of an exhaustible resource, such as crude oil or natural gas. Since the advent of U.S. income taxation, such firms have been permitted to value the depletion of their primary capital assets by reference to either their *cost* or their *fair market value.*

When early tax law limited depletion to a cost basis, it encouraged buying existing production and reserves at market values in order to recover the true value of the resource deposit lost to depletion. At the same time, however, it also discouraged new drilling and exploration primarily because the risks of geological failure were not factored into the cost basis depletion deduction.

To eliminate this bias against reserve replacement by new drilling and to ensure that the value of the capital of a petroleum extraction firm was left unimpaired, the valuation of depletion historically has been based on the greater of cost or fair market value.

Capital valuation for natural resource industries

The statutory five percent depletion allowance of the first income tax was perceived by Congress, the Supreme Court, and the natural resource extraction industries as providing for an inadequate return of capital. This led to the creation of a new method of valuing the *capital* and *income* associated with natural resource extraction.

The Revenue Act of 1916 [14] created a new *reasonable allowance* to acknowledge the *actual depletion* of an exhaustible natural resource deposit, provided it did not exceed the *"capital actually invested"* in the resource. Congress interpreted the *"capital actually invested"* in resource extraction as more than just the cost of exploration and development rights and extraction equipment.

Both Congress and the Treasury Department interpreted the statutory term *capital actually invested*[15] for pre-1913 discoveries to mean the fair market value of the natural resource deposit as of March 1, 1913, the effective date of the first income tax law. However, depletion for post-1913 discoveries was limited to the costs incurred in acquiring the property on which the natural resource was discovered. By valuing the depletion of an exhaustible natural resource at the 1913 value, Congress avoided the imposition of an income tax on what it considered to be *capital.*[16].

13

Commissioner v. Southwest Exploration Co., 350 U.S. 308, 312 (1956).

14

39 Stat 756, Sec 5 and 12, 39 Stat 759 and 769(1916); See also pages A4-A7 of the appendix.

15

T.D. 2447, 19 Treas. Dec. Int. Rev. 31 (1917); See also: T. D. 1675, 14 Treas. Dec. Int. Rev. 16 (1911).

16

It should be noted that this definition of *"capital actually invested"* is similar to the

The nature of *income* and *capital* associated with the extraction of depletable natural resources became the basis upon which natural resource taxation diverged from other areas of taxation. The Treasury Decision that interpreted the Congressional intent of the term "*capital actually invested*" also recognized formally that certain drilling costs; *e.g.*, wages, fuel, and repairs - items that later became labeled as *intangible drilling costs*—were deductible, and that *dry hole* costs also were deductible as a complete loss.

However, the differences in the capital depletion valuations for pre- and post-1913 discoveries (particularly the cost basis limitation) discouraged new exploration and created the impetus for significant changes in the depletion allowance. Until 1969, these changes in the valuation of depletion became the basis for Congress' historical and consistent interpretation of the nature and extent of the true capital depletion associated with most U.S. natural resource extraction industries.

Allowance for discovery depletion

The need for revenues to finance World War I led to enactment of *The Revenue Act of 1918*. Among other things, this Act created a new provision called *discovery* depletion. Its purpose was to eliminate the disparities in valuation between pre- and post-1913 discoveries. Because depletion for post-1913 discoveries was limited to *cost* instead of the *capital actually invested* as defined for pre-1913 properties, Congress acted on the belief that the *capital* of natural resource extraction firms was being taxed as *income.*

This led to the creation of a new method of valuing depletion for petroleum extraction. This method was based on the *discovery value* of an oil or gas deposit. The "discovery value" was a fair market valuation determined within 30 days of its discovery. The discovery value established under this new depletion allowance was based on relatively high World War I crude oil prices. Since the exact extent of a mineral deposit is unknown, this led to uncertainty when either the Internal Revenue Service (IRS) or private geologists attempted to assign a discovery value. Therefore, during this time, reasonable people differed greatly on the fair market value of new discoveries and great controversy surrounded discovery depletion.

Discovery depletion was difficult to administer, requiring at least one expert to evaluate each discovery that qualified for the allowance. At times, several experts were assessing similar and sometimes identical discoveries at significantly different values. The decline in the value of the primary capital asset of a petroleum extraction firm using discovery depletion offset substantial income including non-extraction income.

This, in turn, led to the first *net income limitation*, created by *The Revenue Act of 1921*, which limited the discovery depletion allowance to the net income of the depletable property. Still concerned over the allowance for discovery depletion deductions, Congress, in 1924, further limited the deduction to 50 percent of the net income from the property.[17]

Allowance for percentage depletion

In 1925, in the course of a Senate investigation of the administrative

economic concept of opportunity costs. It was measured by the "*price at which the property as an entirety might have been sold for cash or its equivalent as of that date.*" T.D. 2447, 19 Treas. Dec. Int. Rev. 31 (1917), at page 34.

17 See: Section Two, footnote 47.

practices of the Bureau of Internal Revenue, attention was also given to problems with the discovery depletion allowance. Congress found that the major problem was the inability to precisely and uniformly measure the decline in the value of a depletable capital asset. Contributing to this was the sheer size of early U.S. petroleum discoveries which led to unacceptably large capital depletion deductions.

This led to Congressional debate over the nature and extent of the "*income*" and "*capital*" associated with the extraction of natural resources, particularly petroleum.[18] Because of the inadequacy of capital recovery through *cost* depletion and the administrative expense and complexities inherent in *discovery* depletion,[19] after lengthy debate and major political compromise, Congress created a new capital valuation method designed to avoid both problems. This new depletion allowance, labeled *percentage* depletion, was established at a flat rate of 27.5 percent of sales revenues.

From experience, Congress understood the difficulty of accurately identifying the amount of a petroleum extraction firm's capital that is sold to generate income. By enacting a depletion allowance based on a percentage of gross sales revenues, Congress avoided the administrative complexities, expense, and potential for conflict, of requiring the government and the industry to hire experts to estimate the discovery value of natural resource deposits. The lack of complexity, ease of operation, and its general acceptance as a basis for assessing the capital depletion associated with natural resources, kept the percentage depletion allowance in the tax code, relatively unaltered, for over 40 years. During this time, percentage depletion became further established in the tax code to include many renewable and non-renewable resources.

Intangible drilling costs

From the beginning, *intangible drilling costs* (IDCs) were considered ordinary and necessary expenses of exploring for and producing domestic crude oil and natural gas.[20] Until adoption of the *Internal Revenue Code of 1954*, the 1917 Treasury Decision recognizing the deductibility of IDCs as non-capital expenses of petroleum extraction was relied upon without the need for legislation. Despite the position of the Treasury Department, during the 1940s the IRS challenged the deductibility of IDCs.[21]

This challenge brought an immediate Congressional reaction. Congress reaffirmed by Joint Resolution that IDCs were deductible as essential non-capital costs of petroleum extraction. This also led to explicit codification in the *Internal Revenue Code of 1954* of an election to deduct IDCs in the year incurred.

Beginning in 1976, however, in response to the OPEC oil embargo, Congress began restricting the IDC deduction. Today, *integrated* producers are required to

18
See: Section Two, A5, *et seq.*

19
The Congressional record shows that the Bureau of Internal Revenue spent millions of dollars performing discovery valuations and, the industry spent significantly more.

20
Examples of IDCs include amounts paid for labor, fuel, repairs, hauling and supplies; drilling, shooting, and cleaning of wells; clearing of ground, draining, road making; surveying, and geological work necessary in preparing for drilling of wells; plus the construction of derricks, tanks, and pipelines. In general, IDCs are expenditures which, in themselves, have no salvage value.

21
The Internal Revenue Service advanced the position that IDCs should be capitalized rather than deducted in the year incurred.

recover 30 percent of the IDCs associated with successful U. S. wells over a five-year period. *Independent* producers may elect to recover IDCs in the year incurred for regular income tax purposes. The *alternative minimum income tax*, however, requires that a significant portion of IDCs incurred by all producers [22] be added back to compute alternative minimum income tax liability.

By 1990, U.S. producers subject to either one or both of the IDC add-backs within the alternative minimum tax code, are not guaranteed a full recovery of the capital invested in new drilling. As currently structured, the alternative minimum tax code limits substantially the ability to receive a full return of drilling capital if crude oil prices, revenues and/or producer profitability decline. This result represents a marked departure from traditional theories of petroleum income taxation, both in the United States and elsewhere.[23]

Geological and geophysical expenses

During the 1940s, the IRS decided to challenge the practice of deducting *geological and geophysical* (G&G) expenses in the year incurred. G&G costs include the expenses incurred for specific tests and surveys to provide producers with data, such as contour maps, that can be used to determine the existence or location of hydrocarbon deposits.[24]

Generally, G&G expenditures are made to reduce some of the risks inherent in petroleum exploration. Prior to 1941, the oil and gas industry treated G&G costs as ordinary and necessary non-capital business expenses.[25] The rationale was that the search for oil was a day-to-day activity for anyone in the business and that G&G expenses were among the basic costs of staying in business.

In 1941, the IRS developed the position that some costs of maintaining a land and geological department should be capitalized. The IRS began to distinguish between costs associated with acquiring a property and the costs of determining an exact well site. The Tax Court upheld the IRS view that the latter costs should be treated as IDCs and, therefore, an election could be made to deduct only these expenses in the year they are incurred.[26] Despite the lack of explicit statutory language on this point, G&G expenditures not associated with a specific drilling site are generally amortized over a period of time associated with the continued production from a specific geological area.

22

See: Internal Revenue Code Sections 56(g) and 57 (a).

23

See: Goodman, "*U.S. and Canadian Tax and Fiscal Treatment of Oil and Gas Production*", U.S. Department of Energy, May 1989.

24

See Burke, "*Current Expensing of Geological and Geophysical Costs: A Need for Legislative Clarification*," 34 Okla. L. Rev. 778, 779 (1981).

25

Hall, "*Geological and Geophysical Costs*," Sixteenth Oil and Gas Inst. 584 (1965). The author suggests that prior to 1938 tax payers routinely deducted G&G costs as ordinary and necessary business expenses. See also Ray & Hammonds, "*The Tax Treatment of Oil and Gas Exploration costs for Federal Income Tax Purposes: Geological and Geophysical Expenditures*," 23 Tex. L. Rev. 910, 913 (1950).

26

Louisiana Land & Exploration Co., 7 T.C. 507 (1946), 161 F.2nd 842 (5th Cir. 1947).

Evolution of the Alternative Minimum Income Tax System (1969-1989)

Events leading to fundamental changes in U.S. energy tax policy

U.S. income tax policy affecting petroleum extraction was relatively stable during the period between the creation of the percentage depletion allowance in 1926 and the beginning of the tax reform movement in 1969. Throughout much of this period, U.S. crude oil production was prolific. During World War II, the United States supplied most of the petroleum needs of the allies. However, changes in economic conditions and world events had significant impact on the structure and operation of the U.S. income tax system generally and its major provisions affecting domestic petroleum extraction specifically.[27]

Following World War II, many changes occurred in the U.S. petroleum industry and in the world crude oil market. By the end of the 1940s, the U.S. began to import crude oil, and a decade later the U.S. was no longer self-sufficient in the production of crude oil.

The early 1970s saw the emergence of the Organization of Petroleum Exporting Countries (OPEC). Driven by the Arab oil embargo, the Iranian Revolution, and the Iran-Iraq War, world crude oil prices soared between 1972 and 1982. In response, the U.S. instituted a complex system of controls on the price of domestically produced crude oil. These controlled prices were substantially below the prevailing world price. While the world market price ranged between $30 and $40 per barrel, a significant part of domestic crude oil production was selling for as little as $6 to $11 per barrel.

Starting in 1979, the U.S. began to gradually decontrol the price of domestic crude oil. This process of gradual decontrol ended in January 1981 with the abolition of all remaining oil price controls. In conjunction with the gradual decontrol of domestic prices, Congress passed *The Crude Oil Windfall Profit Tax Act of 1980.* This Act provided for an excise tax on a portion of the difference between the controlled price of domestic crude oil and the market price. The windfall profit tax divided taxable domestic crude oil into different categories and established base prices for each category. The amount a producer received in excess of the statutory base price was defined by Congress as a *windfall profit*. As such, it was subject to tax rates ranging from 30 to 70 percent.[28] Relying on estimates that crude oil prices would reach extremely high levels,[29] Congress scheduled the tax to phase-out by 1993 or after it collected $225 billion.

The windfall profit tax was repealed in 1988 after collecting $88 billion. In July 1986, two years before the repeal of the windfall profit tax, the world price of crude oil had dropped below $10 per barrel, a level that was never anticipated when the tax was enacted.[30]

27
To finance World War I nominal U.S. income tax rates reached 71 percent. During World War II tax rates peaked at 94 percent.

28
The lowest rate of 30 percent applied to various types of high-cost and new production and was lowered later to 22 percent and then 15 percent shortly before the Act's repeal.

29
Estimates of future crude oil prices at that time ranged from $60 to $100 per barrel.

30
Just prior to repeal in October 1987, the statutory base prices for windfall profit taxes ranged from $19.30 to $29.25 per barrel. Windfall profit taxes were not refundable when oil prices declined below the statutory base prices.

The origin and evolution of the tax reform movement

The reform of the U.S. Federal income tax system started with *The Tax Reform Act of 1969* and culminated with *The Tax Reform Act of 1986*. Many economic changes and events occurred in the U.S. and the world during this time. However, the reasons first stated for these reforms were as follows:

"From time to time, since the enactment of the present income tax, over 50 years ago, various tax incentives or preferences have been added to the internal revenue laws. Increasingly, in recent years taxpayers with substantial incomes have found ways of gaining tax advantages from provisions placed in the code primarily to aid some limited segment of the economy....It should not have been possible for 154 individuals with adjusted gross incomes of $200,000 or more to pay no income tax....If taxpayers are generally to pay their taxes on a voluntary basis they must feel that these taxes are fair....To this end it (the House Bill) contains provisions designed to reduce the specific tax advantage that may be received from such items as tax exempt securities, percentage depletion, farm losses, accelerated depreciation of real estate, and deductions for charitable contributions of appreciated property."[31]

Passage of the *Tax Reform Act of 1969* marked the genesis of a new form of income taxation that is now known as the *alternative minimum income tax*. For the petroleum extraction industry, the Act reduced the percentage depletion deduction from its historical level of 27.5 percent to 22 percent for regular income tax purposes. It also created a new *add-on minimum tax*. To compute the add-on minimum tax, a new *excess depletion* provision[32] was used as a basis for computing tax liability. In 1969, when a particular cost was labeled a *preference item*, and thus subject to the add-on minimum tax, the taxpayer was required to pay a flat percentage tax on the expenditure if it exceeded a certain dollar amount. Today the computations are considerably more complicated.

During the time that tax reform was evolving, a number of domestic and international events influenced the tax reform movement. Late in 1973, the first Arab oil embargo occurred and world oil prices very quickly tripled. By 1975, Congressional reaction to soaring oil prices had laid the foundation for the energy tax provisions in *The Tax Reduction Act of 1975*, that:

- eliminated percentage depletion for approximately 70 percent of all U.S. oil production; and
- reduced the percentage depletion rate from 22.5 percent to 15 percent for remaining U.S. production.[33]
- Limited *independent* producers—those with only limited retail or

31

House Report No. 91-413, 93rd Congress, (1969), pages 1645 and 1725. Similar language appears in Senate Report No. 91-552, at page 2027. However, the Senate identified the charitable deduction of appreciated property as the single most important factor leading to the reforms of 1969. Of total itemized deductions of $130 million, $79 million resulted from charitable deductions much of which represented untaxed appreciated property. Ibid., at page 2040.

32

"Excess depletion" is the amount of percentage depletion taken in excess of the "cost basis" of the producing property.

33

In 1975, the 29 largest petroleum companies produced 5,891,000 barrels/day of the total U.S. crude oil production of 8,375,000 barrels/day. Of these 29 companies, only Superior Oil and Louisiana Land were considered *independent* producers. See: Financial Analysis of a Group of Petroleum Companies, Chase Manhattan Bank, 1975.

refining interests—to percentage depletion on 2,000 barrels per day, declining to 1,000 barrels per day by 1980.

- Limited the percentage depletion allowance to 65 percent of the taxpayer's taxable income—the allowance already was limited to 50 percent of net income from the producing property.
- Prohibited proven properties from qualifying for percentage depletion subsequent to their transfer to a new owner.

In 1976, Congress again increased the add-on minimum tax. Responding to further increases in crude oil prices, *The Tax Reform Act of 1976* instituted an add-on tax for certain deductions associated with drilling oil and gas wells. This new provision, labeled the *excess IDC preference*, plus the *excess depletion preference* from the 1969 Act have become permanent elements of the U.S. alternative minimum income tax system.[34]

In 1978, Congress altered the existing structure of the add-on minimum tax and created a new *alternative minimum income tax* (AMT). At this time, however, the new AMT applied only to individuals.

By 1981, the U.S. was experiencing double digit interest rates and inflation coupled with generally adverse economic conditions. To address these problems, Congress passed *The Economic Recovery Tax Act of 1981*. This Act provided general encouragement for new investments with provisions such as accelerated depreciation schedules and investment tax credits. The intent of the Act was to allow quicker recovery of capital investment and to encourage capital formation.

By 1986, interest rates and inflation had declined significantly and the U.S. was experiencing economic expansion. Proponents of the tax reform movement, however, argued that accelerated recovery of capital investments and the other tax provisions that encouraged specific economic activities and investments caused "effective tax rates" among different industries to differ significantly. This, it was argued, caused individuals and companies with apparently similar "*income*" to pay unequal amounts of taxes. It was argued that this lack of "*tax neutrality* ", led to investments being made on the basis of tax considerations rather than profit.[35]

Generally, taxes are considered "*neutral*" when the taxes paid as a percentage of "*income*" are relatively equal among taxpayers and industries. Differences in the taxation of these same activities outside of the United States are not currently taken into account. [36] To ensure

34
Today, corporations are subject to both the *excess IDC* preference contained in IRC Section 57(a) and a second *ACE* IDC preference contained in IRC Section 56(g).

35
"Effective tax rate" is the percentage of "income" paid in taxes. "Income" is defined differently for these and other purposes than it is defined for either regular or alternative minimum income tax purposes, or for SEC purposes. Considerable discussions of the nature of "income" and "capital" for depletable resource industries are reflected in the debates on the depletion allowance that are set forth in Section Two.

36
An underlying intent of *tax neutrality* is to avoid distorting investment decisions on the basis of tax liability. The quantitative analysis in Section Three demonstrates significant differences in the after-tax return from identical investments solely because of the taxpaying status of the investor.

Additionally, failing to account for differences in the level of foreign taxation of the same activity can have a significant affect on *tax neutrality*, the relative after-tax return on greater "tax neutrality" among U.S. industries, *The Tax Reform Act of 1986*, reduced the number of deductions for regular income tax purposes, and expanded the number of *preference items* included within the AMT that was created in 1978. Most importantly, the AMT became universally applicable to all taxpayers—individuals and corporations.

The rise of the tax reform movement has led to significant changes in the structure and operation of the U.S. income tax system generally and the taxation of domestic petroleum extraction specifically. The net effect of the tax reform movement has been to lengthen substantially the time in which U.S. capital investments may be recovered, particularly investments in U.S. petroleum extraction.[37]

The dual structure of the current U.S. income tax system

Today the United States has two separate and, in many respects, conflicting systems: the *regular* and the *alternative minimum* income tax systems. The two systems apply significantly different definitions of *taxable income* and *return of capital*. This is due, in part, to the methods for computing taxable income and, in part, to differences in the underlying theories used to define taxable *income* and *capital* recovery.

Under the regular federal income tax system, taxable income is determined by deducting capital and non-capital costs from gross receipts from all sources. Computation of alternative minimum income tax liability, however, starts with the taxable income calculated for regular income tax purposes and adds back certain capital and non-capital cost recoveries.

Whichever calculation produces the higher tax liability is applicable. If a taxpayer pays AMT in one year, the amount of AMT paid in excess of the otherwise applicable regular taxes is generally available as a credit if and when the taxpayer becomes profitable enough to owe regular income taxes. This credit is not universally available, however, for the portion of AMT paid that is attributable to *excess depletion*. Additionally, if a taxpayer remains subject to the AMT, he never qualifies for a full *return of capital* from his petroleum extraction investments.

With the advent of alternative minimum taxes, conflicts in the definitions of taxable income have arisen. The traditional theory of taxable income has developed through the regular income tax system since its inception. However, the new alternative minimum income tax system is based, in part, on a new concept of income.

To arrive at this new concept of *income*, a taxpayer in the petroleum extraction industry must add back to his regular taxable income four major adjustments: *excess depletion*, *excess IDCs*, *excess depreciation*, and *adjusted current earnings*. Each of these adjustments is based in whole or in part on a traditional capital or non-capital cost recovery principle. Many expenses which Congress has historically recognized in the tax code as allowable capital and non-capital costs of generating income from the extraction of petroleum are now treated as "income" and used to determine alternative minimum income tax liability. These adjustments were either added or expanded by *The Tax Reform Act of 1986*.

investments generally, and petroleum investments specifically.

37 It should be noted that during the same time the U.S. lengthened the minimum time that investors qualify for a return of capital from petroleum extraction investments, many other non-OPEC oil producing countries did just the opposite.

The Tax Reform Act of 1986

The *Tax Reform Act of 1986* culminated two decades of tax reform. As in earlier attempts at tax reform, Congress sought to simplify the tax code in order to improve voluntary compliance and increase the perceived fairness of the federal income tax system. However, the 1986 Act, unlike earlier reform legislation, instituted a major revision of the U.S. income tax system.

The President and Congress attempted to eliminate what was perceived as a substantial tax bias in U.S. investments. By eliminating numerous deductions, credits, and capital cost allowances, it was intended that investments under the new code would be based on the underlying profitability of a particular project, instead of its tax consequences. Moreover, by eliminating such deductions, credits, and allowances, and designating additional items as *tax preferences*, the tax base was broadened—thus increasing the amount of revenue subject to income taxes, and allowing individual and corporate tax rates to be reduced, while still collecting the same amount of tax revenue.

Today, the major elements of the regular U.S. income tax system which help to define taxable income from oil and gas production are the tax rates and the remaining capital and non-capital cost recovery provisions. Cost recovery provisions specifically affecting oil and gas investments in the United States include percentage and cost depletion, depreciation and deductions for the recovery of IDCs and G&G expenses. Additionally, there are regular income tax provisions limiting the utilization of net operating losses, passive losses, percentage depletion and investment tax credits.

In addition to the regular income tax system, a number of AMT provisions, by serving to redefine that portion of revenues that will be treated as *"taxable income"*, directly and indirectly affect after-tax rate of return on investments in U.S. petroleum extraction. These provisions are:

- *excess depletion*,
- *excess IDCs*,
- *excess depreciation*,
- a *book income adjustment*, and
- starting in 1990, a new add-back for *adjusted current earnings* (ACE).

Under the AMT system, *taxable income* for petroleum extraction firms includes items that Congress historically allowed as non-taxable capital and non-capital cost recoveries. While the excess depletion and excess IDCs provisions previously had only limited applicability, the 1986 Act expanded and extended them to all individuals and corporations. The provisions adding back to *taxable income* amounts for *excess depreciation*, *adjustments for book income* and *adjusted current earnings* are more recent; and, while not specifically directed toward the petroleum extraction industry, they have nevertheless had a significant impact on domestic petroleum production.

AMT tax rates generally are lower than regular tax rates. However, since the capital investment itself gives rise to AMT liability rather than the production of income in a traditional or historic sense, when applicable, the net effect of the alternative minimum income tax system is to increase substantially the portion of gross oil and gas sales revenues subject to federal income taxes, regardless of whether there is "income" in a true economic sense.

Excess depreciation. The *excess depreciation* provision adds back to taxable income the difference between two depreciation methods and has the effect of delaying capital cost recovery. Significantly, the petroleum extraction industry uses substantial amounts of equipment that would otherwise qualify for faster cost recovery.

Book income adjustment. Prior to 1990, the *book income adjustment* added back to a taxpayer's AMT taxable income 50 percent of the difference between the *book* income a corporation reported to its shareholders and the amount it computes as AMT taxable income.

Because of the inconsistencies in both the purposes and definitions of *income* and *capital* between IRS and SEC rules, between 1986 and 1990, a corporation was potentially subject to alternative minimum income tax liability solely on the basis of certain non-income tax accounting rules.

Adjusted current earnings preference. Starting in 1990, the amount of AMT *taxable income* of all firms, including domestic petroleum extraction firms, includes an add-back called the *adjusted current earnings* (ACE) preference. The ACE adjustment is a substitute for the *book income* adjustment.

It starts with a concept of income called *earnings and profits* and then makes certain adjustments. The principal application of this concept has been to help determine the amount of corporate income that will be subject to taxation again following distribution to shareholders as dividends. As the portion of corporate income that is characterized as *earnings and profits* increases, so does the share of corporate dividends that will be subjected to double taxation upon distribution to shareholders. If a corporation pays a dividend that is not considered *earnings and profits*, it is considered a *return of capital.*

Percentage depletion is not allowable when computing the ACE adjustment. IDCs are generally capitalized rather than expensed and depreciation is substantially reduced. As with the AMT generally, a corporation could incur real economic losses yet pay sizable alternative minimum tax payments solely by virtue of the change in the traditional definition of "*income*" embodied within this preference.

Implications For U.S. Petroleum Income Tax Policy

U.S. tax policy and U.S. energy policy have gone through significant change during the 20th century. What the U.S. historically recognized as the recovery of capital and non-capital costs of petroleum extraction, is now labeled *income* subject to either regular or alternative minimum income tax liability.

Depletion allowance. The historical allowance for percentage depletion has been substantially eliminated. From 1926 through 1969, percentage depletion was 27.5 percent of sales revenues for all U.S. production and applicable to all U.S. producers. Now it is 15 percent of sales revenues for significantly less than 30 percent of total U.S. production and only for certain U.S. producers who qualify for a maximum of no more than 1000 barrels per day. Percentage depletion also is now limited to:

- 50 percent of the net income of the property from which the petroleum was produced, and
- 65 percent of the producer's taxable income.

Each of these limitations restricts the allowance for percentage depletion if either prices or profitability decline. Percentage depletion is also subject to a *transfer rule* and an *add back* for computing AMT liability as *excess depletion*. Lastly, percentage depletion is also added back indirectly to compute AMT liability as part of either the *book income* or *ACE adjustment*.

Intangible drilling costs. Deductions for IDCs have long been allowed by the Congress and the courts as necessary non-capital expenses of petroleum extraction. Today, however, 30 percent of IDCs incurred by *integrated* producers are required to be capitalized and all producers must now compute AMT liability by adding back either one or two IDC preferences. This also increases the after-tax cost of U.S. petroleum extraction, particularly if prices, revenues or profitability decline.

Geological and geophysical expenses. Initially, G&G expenditures also were considered ordinary and necessary non-capital costs of petroleum extraction. However, since the 1940s, most G&G expenses must be capitalized. G&G expenses are particularly important to help locate hard-to-find deposits of petroleum. Many of the new geological and geophysical techniques are sophisticated and very expensive. Other traditional capital cost recovery deductions, such as depreciation and differences in either *book income* or *earnings and profits* are now computed as part of a firm's AMT income.

Conclusions

The regular income tax system has provided for recovering the capital costs of oil and gas extraction based on the *greater* of the cost or the value of the oil and gas reserves depleted. By contrast, however, the alternative minimum income tax system has created a new definition of *"taxable income"*. Under this alternative definition of *"taxable income"*, the recovery of many capital and non-capital expenditures, such as depletion, depreciation, and IDCs, are limited severely or in some cases prevented.

The effect of these multiple limitations on cost recoveries has been to: a) increase the portion of "gross receipts" or sales revenues treated as taxable income; b) increase the after-tax cost of extracting petroleum in the United States; c) reduce the revenues available for reinvestment to replace depleting domestic petroleum reserves; d) lower the level of geological risks that will find acceptable economics in the United States; e) decrease the after tax return from extraction investments as prices, revenues or profitability decline; and f) cause different taxpayers to have substantially different after-tax returns from the same petroleum extraction investment.

Section Two

History of the U.S. Petroleum Depletion Allowance

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Introduction

Article 1, Section 8 of the U.S. Constitution, provides that "*the Congress shall have the Power to lay and collect Taxes, Duties, Imposts and Excises, to pay the Debts and provide for the common Defence and general Welfare of the United States*". However, Article 1, Section 2 of the Constitution limits this power by stating that "*...direct taxes shall be apportioned among the several states which may be included within this Union, according to their respective numbers.*" The Constitution does not define *direct* taxes nor does it mention *income* taxes. However, it is clear that the constitutional rule requiring the apportionment of direct taxes in accordance with a population census was designed to prohibit the taxation of property that might be disproportionately located in a particular state or region.[1]

The creation of the modern U.S. income tax system evolved from the landmark case, Pollock v. Farmers' Loan & Trust Co.[2] In this case the Supreme Court struck down *The Income Tax Act of 1894*.[3] In Pollock, the Supreme Court declared it unconstitutional for the Federal Government to tax property or capital directly. Rehearing the same case later that year, the Supreme Court further declared that the taxation of income derived from property is equivalent to taxation of the property itself and, therefore, unconstitutional.[4] The holding in this case prohibiting the Federal Government from imposing an income tax without apportionment created the impetus to amend the Constitution.

On February 25, 1913, the 16th Amendment to the Constitution was ratified. This Amendment granted Congress the power "*...to lay and collect taxes on incomes from whatever source derived, without apportionment among the several states, and without regard to any census or enumeration.*" The Amendment removed the constitutional requirement that *income* taxes be imposed in proportion to the population.

This Amendment did not change the constitutional rules affecting the taxation of capital or property. Consequently, throughout the history of U.S. income taxation, numerous provisions have evolved to avoid the imposition of income taxes directly on capital. To be equitable, these provisions generally take into account the nature of the activity being taxed when distinguishing between the firm's *income* and *capital*. The provisions affecting the extractive industries and petroleum extraction in particular reflect the unique characteristics of this activity. Unlike a manufacturing enterprise or many real estate activities, petroleum extraction requires the sale of the primary capital assets of the enterprise to generate the revenues necessary to continue operations. This somewhat unique characteristic of petroleum extraction is the primary reason that the U.S. income tax code has developed separate provisions for this industry. The allowance for depletion is one such provision.

Depletion was created to account for the loss to a firm that results from the sale of the primary capital assets of the enterprise.

1
For a discussion of the constitutional distinctions between the direct and indirect taxation of income and capital, see generally: The License Tax Cases, 5 Wall. 462, 471 (1866); The Federalist Papers, No. 36 and 54; and Hylton v. United States, 3 Dall. 171 (1796).

2
157 U.S. 429 (1895).

3
The Income Tax Act of 1894 imposed a two percent annual tax on the gains, profits, and income received by every citizen of the United States, if the gains, profits, or income were derived from any kind of property, rents, interest, dividends, or salaries, or from any profession, trade, employment, or vocation carried out in the United States or elsewhere.

4
Pollock v. Farmers' Loan and Trust Company, 158 U.S. 601 (1895).

Since the extent of petroleum deposits are unknown and must be estimated, the measurement of this loss is necessarily inexact. Therefore, Congress has changed the measurement of this loss by adjusting the operation and scope of the depletion allowance on many occasions since the ratification of the 16th Amendment. However, the history of the depletion allowance predates the first constitutionally enacted income tax law.

The Corporation Tax Act of 1909

In 1909, Congress established an excise tax in *The Corporation Tax Act of 1909*. In contrast to *The Income Tax Act of 1894*, the purpose of *The Corporation Tax Act* was not to tax property, *per se*, but to tax corporations organized for profit.[5] *The Corporation Tax Act* imposed a tax on corporate gross income and provided for certain deductions, including one for the *depreciation of property*. Even though the 1909 Act did not provide explicitly for a deduction to account for the depletion of mineral reserves, the Treasury department interpreted the depreciation provisions of the Act to apply to the depletion of mineral deposits including oil and gas.[6]

In Stratton's Independence Ltd. v. Howbert,[7] the Supreme Court decided that, although it recognized the unique character of a mining property, *i.e.*, that it involves the production of income from depleting or *wasting* assets, it was not proper for the Treasury department to infer a depletion deduction that was not explicitly provided by Congress.

The Supreme Court concluded that the *Corporation Tax Law of 1909* was constitutional as it was not in any proper sense an income tax law, but rather an excise tax upon the conduct of business in the corporate form. The Court stated:

> *"It was reasonable that Congress should fix upon gross income, without distinction as to source, as a convenient and sufficiently accurate index of the importance of the business transacted. And from this point of view, it makes little difference that the income may arise from a business that theoretically or practically involves a wasting of capital."* [8]

In the Stratton case, both the Treasury department and the mining company agreed that the actual depletion of the ore body was equal to the fair market value of the ore produced and sold. The Supreme Court, decided that the Treasury department did not have the authority to interpret the depreciation provision to include depletion. Instead, the Court ruled only on whether Congress was properly exercising its constitutional power to impose an excise tax on gross corporate receipts, not whether those receipts were *income* or a *return of capital*.[9] It was significant, however, that the Court recognized for the first time an inherent difference in a business that relied on the sale of its primary capital assets—that

5
Doyle v. Mitchell Bros. Co., 247 U.S. 179, 183 (1918).

6
T. D. 1675, 14 Treas. Dec. Int. Rev. 16, 22 (1911). In this decision, Treasury allowed a deduction for *depreciation* based on the fair market value of the minerals as of January 1, 1909.

7
231 U.S. 399 (1913).

8
Ibid. at 417.

9
It should be noted that the *return of capital* doctrine was enunciated by the Supreme Court in the case of Burnet v. Logan 283 U.S. 404 (1931), as follows: *"...in order to determine whether there has been gain or loss, and the amount of the gain, if any, we must withdraw from the gross proceeds an amount sufficient to restore the capital value that existed at the commencement of the period under consideration."*
See also Doyle v. Mitchell Bros. Co., 247 U.S. 179, 184,185

also were depletable natural resources—for the generation of income.

In Von Baumbach v. Sargent Land Co.,[10] the Supreme Court further explained its decision not to interpret the *depreciation* provision as synonymous with a *depletion* allowance as follows:

> "*It would be a strained use of the term depreciation to say that, where ore is taken from a mine in the operation of the property, depreciation, as generally understood in business circles, follows. True, the value of the mine is lessened from the partial exhaustion of the property, and, owing to its peculiar character, cannot be replaced. But in no accurate sense can such exhaustion of the body of the ore be deemed depreciation. It is equally true that there seems to be a hardship in taxing such receipts as income, without some deduction arising from the fact that the mining property is being continually reduced by the removal of the minerals. But such consideration will not justify this court in attributing to depreciation a sense which we do not believe Congress intended to give it in the Act of 1909,*" 11

The Tariff Act of 1913

The 16th Amendment to the Constitution, which was ratified by the States on February 25, 1913, allowed Congress "*to lay and collect taxes on income from whatever sources derived.*" 12 On March 1, 1913, Congress passed *The Tariff Act of 1913*, imposing a tax on both personal and corporate incomes. In this Act, Congress included a specific provision for *depletion*.[13] When computing the amount of income subject to this new income tax, a corporation was allowed the following deduction:

> "*...a reasonable allowance for the exhaustion, wear, and tear of property arising out of its use or employment in the business, not to exceed, in the case of mines, 5 per centum of the gross value of the mine output for the year for which the computation is made, but no deduction shall be made for any amount of expense of restoring property or making good the exhaustion thereof for which an allowance is or has been made.*" 14

The Supreme Court first reviewed the depletion allowance in the case of Stanton v. Baltic Mining Company.[15] In that case, Baltic contended that the five percent depreciation allowance was inadequate to

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10
Von Baumbach v. Sargent, 242 U.S. 503 (1917), involved a suit to recover taxes paid under protest, which had been assessed under the Corporation Tax of 1909, on revenues received from a lessee under a mining lease. The Court found that the money paid by the lessees to the respondent was income, that properly could be used to measure the amount of the excise tax imposed under the 1909 Act. 242 U.S. 503,522 (1917).

11
Ibid. at 524-525. See also U.S. v. Biwabik Mining Co., 247 U.S. 116 (1918); and Goldfield Consol. Mines Co. v. Scott, 247 U.S. 126 (1918).

12
According to the Supreme Court in Brushaber v. Union Pac. R.R., 240 U.S. 1, 17 (1916), "*it was not the purpose or effect of [the Sixteenth] Amendment to bring any new subject within the taxing power. Congress already had power to tax all incomes. But taxes on incomes from some sources had been held to be 'direct taxes' within the meaning of the Constitutional requirement as to apportionment...The Amendment relieved from that requirement and obliterated the distinction in that respect between taxes on income that are direct taxes and those that are not, and so put on the same basis all incomes 'from whatever source derived'.*"

13
38 Stat. 169.

14
While the Act only mentioned mines, the Bureau of Internal Revenue interpreted this provision to include oil and gas wells. Legislative History of Depletion Allowances, Staff of the Joint Comm. on the Internal Revenue Taxation, 81st Cong., 2nd sess., pt. 9, 1 (Comm. Print 1950).

15
240 U.S. 103 (1916).

provide for the exhaustion of the ore body.[16] In effect, therefore, this was a tax on property because of its ownership, which should be subject to apportionment under the Constitution.[17] Relying on its previous holding that Congress was able to tax the gross revenues of a mining enterprise under the pre-16th Amendment excise tax of *The Corporation Tax Act of 1909*, the Supreme Court upheld the new income tax despite a perceived unfairness of the depletion provision.

Despite the initial inadequacy of the depletion allowance, the Supreme Court consistently has recognized that some portion of the revenues received from the sale of an exhaustible resource is, in fact, a *return of the capital* invested in the enterprise:

> *"The purpose for the deduction for depletion is plain and has been many times declared by this Court. 'It is permitted in recognition of the fact that the mineral deposits are wasting assets and is intended as compensation to the owner for the part used up in* production.'" 18

> *"[The depletion] exclusion is designed to permit a recoupment of the owner's capital investment in the minerals so that when the minerals are exhausted, the owner's capital is unimpaired..."* 19

After the Baltic case, Congress was convinced that the arbitrary five percent statutory rate of depletion was inadequate to prevent the impairment of the capital inherent in petroleum extraction. This led to significant changes in the allowance for depletion.

The Revenue Act of 1916

The Revenue Act of 1916 [20] was the first Act to make special mention of oil and gas wells and the first to explicitly use the word *depletion*. The provision changing the deduction for depletion was first introduced in H.R. 16763 by the Senate Finance Committee.[21] Senator Chilton of West Virginia explained the reasoning behind the change:

> *"...The old law, making a deduction of not exceeding 5 percent, ... struck the committee as being absolutely an arbitrary one, and based upon no reason....The oil and gas producers...want only the actual depletion. This they failed to get under the old law, and they will get it under this amendment."* 22 (emphasis added)

16
Under this depletion provision it was possible to recover less than the actual cost of the minerals in place.

17
Article 1, Section 9, Clause 4 of the Constitution requires that *"[n]o Capitation, or other direct, Tax shall be laid, unless in Proportion to the Census or Enumeration herein before directed to be taken."*

18
Parsons v. Smith, 359 U.S. 215, 220 (1959), citing Helvering v. Bankline Oil Co., 303 U.S. 363, 366 (1938).

19
Commissioner v. Southwest Exploration Co., 350 U.S. 308, 312 (1956). See also United States v. Ludey, 274 U.S. 295 (1927): The depletion charge represents the reduction in the mineral contents of the reserves from which the product is taken.; Anderson v. Helvering, 310 U.S. 404, 408 (1940): Depletion is a deduction from gross income as compensation for the consumption of capital.; Kirby Petroleum Co. v. Commissioner, 326 U.S. 599, 603 (1946): The 27 1/2 percent [depletion allowance] is the statutory restoration of the taxpayer's capital. ; Parsons v. Smith, 359 U.S. 215, 220 (1959): The purpose of the depletion deduction is to permit the owner of a capital interest in the minerals in place to make a tax-free recovery of that depleting capital asset.

20
39 Stat. 756, 759 (1916).

21
S. Rep. No. 793, 64th Cong., 1st Sess., pt. 1, 4-5 (1916).

22
53 Cong. Rec. 13287 (1916).

The Revenue Act of 1916 provided for a depletion deduction as follows:

> *"All losses ...including...in the case of oil and gas wells a reasonable allowance for actual reduction in flow and production to be ascertained not by the flush flow, but by the settled production or regular flow."* 23

The Treasury department interpreted this provision as follows:

> *"The purpose of this provision is to afford a means whereby the individual or corporation owning oil or gas producing properties may, during the period of operation, deduct from gross income the cost of or the* ***capital actually invested in,*** *the natural deposits...By capital actually invested, as herein used, is meant the fair market value of the properties as of March 1, 1913 if acquired prior to that date, or their actual cost if acquired subsequent to that date."* 24 (emphasis added)

For pre-1913 discoveries the *capital actually invested* was defined by both Congress and the Treasury department as the fair market value of the discovery as of the enactment of the first income tax law. The legislative history makes it clear that this determination was based on the constitutional rules concerning the imposition of a direct tax on property. In this case, Congress determined that the *property* involved was the natural resource deposit itself. To avoid imposing an *income* tax on the *capital* that existed before income taxation, it was necessary to provide a depletion allowance that protected the value of property as of that date.

The *reasonable allowance for actual reduction in flow* was calculated by measuring the well's flow rate once it became settled or stable and again at the end of each tax year. The reduction in flow rate was computed as a ratio and the ratio applied against the well's post-1913 cost or pre-1913 value to determine the allowance for depletion.[25] The *decline-in-flow* method was consistent with the then accepted practice of the oil industry.[26] The Senate recognized that because the flow method was based strictly on physical measurement to calculate the decline in value, it did not consider other economic events which could affect the value *e.g.*,changes in prices, availability of a market, transportation, new discoveries, *etc.*[27]

In the case of New Creek Co. v. Lederer,[28] when called upon to determine what constituted a reasonable allowance for depletion the court stated as follows:

> *"Clearly, Congress did not know. And this is entirely natural because of the variable factors entering inevitably into such problems as they arise with reference to mines under varying conditions...The value of such property is usually in the mines which lie within it... Their mineral extent and money value are factors impossible of precise ascertainment. Yet, on these factors any allowance for depletion of capital or the corpus must be based."* 29

23
The Revenue Act of 1916, 39 Stat. 756 , §5, §12, 39 Stat. 759 and 769 (1916).

24
T.D. 2447, 19 Treas. Dec. Int. Rev. 31 (1917).

25
The Revenue Act of 1916, §12(a)(2), §5(a)(8).

26
Freeman, Percentage Depletion for Oil–A Policy Issue, 30 Ind. L. J. 399, 405 n.16.

27
54 Cong. Rec. 13286 (1916). Because the depletion allowance was measured by the reduction in flow without regard to new discoveries, it caused a producer that invested in new production to get a lower depletion allowance. T.D. 2447, 19 Treas. Dec. Int. Rev. 31, 33-4 (1917).

28
295 F. 433 3rd Cir. (1924).

29
Ibid., at 435-436.

The Supreme Court, in U.S. v. Ludey,[30] acknowledged that the depletion allowance only was a rough estimate by the Congress. But Congress concluded that it was better to act upon a rough estimate than to ignore the fact of depletion.

Significantly, *The Revenue Act of 1916* disallowed deductions for depletion when the total allowance exceeded the pre-1913 value or the post-1913 cost. This introduced what later became the concept of *basis* for depleting oil and gas producing assets. However, the basis was not limited to the specific dollar cost of the property on which discovery was made. Instead, the Treasury department specifically recognized that the capital actually invested in pre-1913 discoveries was the *value* of the discovery as of that date, as opposed to the *costs* incurred in the discovery.

On several occasions, the Supreme Court examined the 1916 depletion provision and outlined Congress' reasoning in enacting it. The Court explained that the 1916 Act's deduction for depletion in the case of mines was a special application of the general rule of the statue allowing a deduction for exhaustion of property.[31] In the Ludey case, the Supreme Court described the purpose of the depletion allowance as follows:

> *"The depletion charge permitted as a deduction from the gross income in determining the taxable income of mines for any year represents the reduction in the mineral contents of the reserves from which the product is taken. The reserves are recognized as wasting assets. The depletion effected by operation is likened to the using up of raw material in making the product of a manufacturing establishment. As the cost of the raw material must be deducted from the gross income before the net income can be determined, so the estimated cost of the part of the reserve used up is allowed. The fact that the reserve is hidden from sight presents difficulties in making an estimate of the amount of the deposits. The actual quantity can rarely be measured. It must be approximated ... And because the quantity originally in the reserve is not actually known, the percentage of the whole withdrawn in any year, and hence the appropriate depletion charge is necessarily a rough estimate....But Congress concluded, in the light of experience, that it was better to act upon a rough estimate than to ignore the fact of depletion ...The proviso limiting the amount of the deduction for depletion to the amount of the capital invested shows that the deduction is to be regarded as a return of capital, not as a special bonus for enterprise and willingness to assume risks."*[32]

The U.S. involvement in World War I renewed the debate over the nature of *income* and *capital* in the petroleum extraction industry. To finance the war, Congress raised the income tax rate from its nominal one percent rate. Much of the increase in the income tax was by means of a war *excess profits* tax. Excess profits were taxed by placing a graduated tax on the profits that exceeded a certain percentage of a *return on the capital* invested in the business.

This presented a particular problem for the petroleum industry. It highlighted the difference in income tax treatment between those who purchased an existing resource and those who explored for such a resource. Those who purchased had a high cost basis, which lessened the impact of this tax, while those who explored had a much lower cost basis. When the latter produced they were hit heavily by the tax.

30
274 U.S. 295 (1927).

31
Lynch v. Alworth-Stephens Co., 267 U.S. 364, 371 (1925).
32
U.S. v. Ludey, 274 U.S. at 302-303.

This unfavorable tax situation was aggravated further by three factors:

- there was a capital gain tax on any profits that might be made on a sale of property equal to the highest rate of the war excess profits tax;
- the Treasury interpreted the *Revenue Act of 1916* to allow cost depletion only to the owner of the land in fee; the oil and gas lessee was allowed no depletion at all, cost or otherwise; and
- the U.S. Fuel Administration had set a maximum price on the sale of crude oil.

These factors were the impetus for the next significant change in the depletion provision.

The Revenue Act of 1918

The Revenue Act of 1918 [33] substantially revised the allowance for depletion by introducing the concept of *discovery* depletion for oil and gas wells. This new allowance permitted taxpayers to use the *fair market value* of the oil or gas at the time of the discovery, or within thirty days of the discovery, as the basis for depletion for wells discovered after 1913. Certain wells were still held to the *reasonable allowance* standard established in *The Revenue Act of 1916*. In addition, the scope of depletion was broadened to include other natural resource deposits and timber.[34]

The bill, H.R. 12863, as initially drafted by the House Ways and Means Committee, did not include the discovery depletion allowance, but instead merely extended the 1916 Act's *reasonable allowance*.[35] Representative Chandler of Oklahoma did not believe that the House Ways and Means Committee had gone far enough to relieve the inequalities that the extractive industries experienced in determining *income* subject to taxation. During the debates on the revisions to the income tax laws in 1918, an excellent insight into the reasons for expanding the depletion allowance was provided by Representative Chandler, as follows:

> *"I do not believe that the committee has eliminated these inequalities, but to the contrary, so far as it affects certain industries. The inequities I refer to are the lead, zinc mining and the production of oil and gas...throughout the United States, which is different from the ordinary business. It is full of failures and is highly*

33
40 Stat. 1057 (1919).

34
Sections 214(a)(10) and 234(a)(9) of *The Revenue Act of 1918* provided as follows: *"In the case of mines, oil and gas wells, other natural deposits, and timber, a reasonable allowance for depletion, and for depreciation of improvements, according to the peculiar conditions in each case, based upon cost including cost of development not otherwise deducted: Provided, That in the case of such properties acquired prior to March 1, 1913, the fair market value of the property (or the taxpayer's interest therein) on that date shall be taken in lieu of cost up to that date: Provided further, That in the case of mines, oil and gas wells, discovered by the taxpayer, on or after March 1, 1913, and not acquired as the result of purchase of a proven tract or lease, where the fair market value of the property is materially disproportionate to the cost, the depletion allowance shall be based upon the fair market value of the property at the date of the discovery, or within thirty days thereafter; such reasonable allowance in all the above cases to be made under rules and regulations to be prescribed by the Commissioner with the approval of the Secretary. In the case of leases the deductions allowed by this paragraph shall be equitably apportioned between the lessor and lessee."* (40 Stat. 1068, 1078-79).

35
The Committee report in reference to depletion stated merely: *"The depletion provision of existing law does not grant an allowance for cost of development. In case of mines, oil and gas wells such an allowance seems only equitable and fair and the bill provides that a reasonable allowance in such cases be allowed for depreciation of improvements. The bill also corrects an inequality of the present law by providing for an equitable apportionment of the depletion allowance between lessor and lessee."* H. Rept. No. 767, 65th Cong., 2nd sess. 30 (1918).

hazardous and speculative. The risks are such that the incentive is not merely usual interest return on capital invested, as may be the case in other business, but a reward out of proportion to such usual returns. This reward of unusual return comes oftentimes after a fruitless endeavor extending over a period of years in losing or unprofitable adventures, with no return whatsoever, and usually with total loss of capital...This incentive that extends the development and opens new mines and new oil and gas wells is the hope of finding some day a mine or well that will compensate for past hardships, privations, and losses....

"I also wish to call to your attention the fact that 90 percent of the oil produced is taken from new wells during the first four years of their existence. At least 50 percent of this amount is produced during the first year of a wells existence. It is therefore necessary, in order that production may be kept from declining, that new wells in large numbers be drilled....History of the oil fields show that less than 1 out of 100 wildcat adventures are successful, over 99 percent being a total loss to the parties entering upon the undertaking. Less than 10 percent of successful ventures return to the parties their investments. Of this 10 percent possibly 2 percent are big strikes which you hear so much about....

"The law should at least give to oil producers and miners of this character, where the life is short and uncertain, 15 percent credit on capital; again, depletion and depreciation allowances should be so provided and administered that the tax would be on profit not capital. As now administered the capital is returned by depletion(cost) and depreciation allowances over the estimated life of the individual mine. This may and oftentimes works as a great hardship...[after citing two technical examples of the operation of the tax system, Congressman Chandler states]...*This is a tax on capital, not income."* 36

An amendment, introduced by Representative White of Ohio to protect the wildcatter's capital, gave a deduction for an amount not to exceed 10 percent of the value of the oil removed during the year.[37]

The House version of the bill was amended by the Senate Finance Committee to include a provision allowing the taxpayer to use as the basis for depletion, the *discovery value* of the property. The Committee report stated:

"The prospector for mines or oil and gas frequently expends many years and much money in fruitless search. When he does locate a productive property and comes to settle it seems unwise and unfair that his profit be taxed at the maximum rate as if it were ordinary income attributable to the normal activities of a single year. To stimulate prospecting and exploration, the committee has limited the surtax to 20 percent of the selling price in the case of a bona fide sale of mines, oil or gas wells where the principal value was demonstrated by prospecting, exploring, or discovery work done by the taxpayer." 38

36
56 Cong. Rec., 10339, 65th Cong., 2nd Sess. (1918).

37
56 Cong. Rec. 65th Cong., 2nd Sess. 10539-10542 (1918), Congressman White of Ohio stated his reasoning behind the amendment as follows: *"During the consideration in the Committee of the Revenue Act of 1916 I stated that I feared the rates of taxation imposed on the oil industry would result in a falling off of the production of crude oil, and my prophecy has proven accurate, and in the face of the lessened activity of the wildcatter and the resulting decline in production, the Committee has authorized me to offer this amendment."* 56 Cong. Rec. 65th Cong., 2nd Sess. 10540 (1918).

38
S. Rept. No. 617, 65th Cong., 3rd Sess., 6 (1918). The Act had a special treatment for the sale of mines, oil or gas wells for the surtax rates. For the sale of mines, oil or gas wells, where the principal value has been demonstrated by dis-

The new *discovery depletion* provision was explained on the Senate floor by Senator Penrose of Pennsylvania, the ranking Republican member of the Finance Committee, as follows:

> "*The committee gave very careful consideration to the question of depletion. The just taxation of income derived from the operation of mines and of oil and gas wells is a particularly difficult matter.* ***This is due to the fact that part of what apparently is income is in reality a mere return of the capital of the enterprise.*** *When, for example, a ton of coal is sold the excess of what is received from the cost of mining of that ton of coal is by no means all income; part of that excess must be treated as a repayment of what was invested in the mine from which the coal was taken. Such allowances for the extractive industries are covered by the depletion provisions....*" 39 (emphasis added)

The bill as amended was approved by both Houses without further debate.[40]

The passage of discovery depletion in 1918 extended the fair market valuation for pre-1913 discoveries to new discoveries made after 1913. For the next 50 years, the loss of capital attendant to the depletion of petroleum deposits was measured by the greater of a portion of the fair market value or the costs incurred in acquiring, finding, and developing oil and gas deposits.[41]

The Revenue Act of 1921

After the institution of *discovery* depletion, the valuation of the depletion was based on the *discovery value* of a new oil or gas deposit. However, since the discovery value was based on higher prices prevailing during the war and the *flush* flow, as opposed to the *settled* flow, of a new discovery, the amount of the depletion allowance in any given year could exceed the net income from the business. This led to discovery depletion being used to offset non-oil, gas, or mining income.

The Revenue Act of 1921 [42] amended *The Revenue Act of 1918* by limiting discovery depletion to the net income from the depletable property.[43] The Act also provided a new special capital gains rate and disallowed a carry-forward of losses attributable to depletion if the basis for the carry-forward was discovery value rather than cost. This provision was intended to prevent companies from escaping tax on income from non-mining sources by using offsetting depletion deductions from extractive resources industries. [44]

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covery work done by the taxpayer, the surtax rate was not to exceed 20 percent as compared to other sources of income where the rate could go as high as 65 percent. This provision was in recognition of the fact that the prospector's business was to find the resource not the development or production of the resource. After making a discovery, the prospector would normally be required to sell the property in order to have the funds necessary to continue prospecting.

39
57 Cong. Rec. 549, 65th Cong., 3rd Sess. (1918).

40
See 57 Cong. Rec. 554, 65th Cong., 3rd Sess. (1918) and 57 Cong. Rec. 3007, 65th Cong., 3rd Sess. (1919).

41
H. Rept. No. 1037, 65th Cong., 3rd Sess. (1919).

42
42 Stat. 227 (1921).

43
Ibid. 42 Stat. 227, 241 (re: individuals); 42 Stat. 227, 256 (re: corporations).

44
During the hearings before the Senate Finance Committee, the Treasury Department recommended that the allowance for discovery depletion be limited to 50 percent of the net income from the property depleted. The committee rejected the 50 percent limitation and substituted a limit of 100 percent of net income. Its report stated:

In a landmark case interpreting *The Revenue Act of 1921*,[45] the Supreme Court acknowledged that, prior to 1918, depletion that was limited by costs favored those who paid for discoveries and disfavored those who explored for new discoveries. With the advent of depletion for new discoveries based on fair market valuation, those who explored for new discoveries were no longer disadvantaged by the post-1913 cost-based depletion allowance. In addition, the Supreme Court discussed the nature of an economic interest in mineral deposits. Only *economic* interests qualify for the depletion allowance.

The Revenue Act of 1924

The Revenue Act of 1924[46] adopted a Treasury proposal made in 1921 to limit the allowance of discovery depletion to 50 percent of the net income from the property depleted.[47] The provision was accepted by the House and an identical amendment was reported by the Senate Finance Committee.[48] Despite efforts to limit discovery depletion, Congress still was dissatisfied with the manner in which discovery depletion was operating. At this time, the Supreme Court was grappling with issues of who qualified for depletion and whether the nature of payments to a lessor were income or a return of capital.[49]

"*... in order to make certain that the depletion deduction when based upon discovery value shall not be permitted to offset or cancel profits derived by the taxpayer from a separate and distinct line of business, it is provided that the depletion allowance based on discovery value shall not exceed the net income, computed without allowance for depletion, from the property upon which the discovery is made, except where such net income so computed is less than the depletion allowance based on cost or the fair market value as of March 1, 1913.*" S. Rept. No. 275, 15, 67th Cong., 1st Sess. (1921).

45
Palmer v. Bender, 287 U.S. 551, 558 (1933). In this case the Supreme Court incorporated the return of capital concept into the definition of an economic interest. The holder of an economic interest is treated as the producer of the oil or gas for federal income tax purposes. Those who must look to the oil and gas for a *return of capital* are considered to be "holders of economic interests." The Supreme Court explained an *economic interest* as follows: "*...[t]he language of the statute is broad enough to provide, at least, for every case in which the taxpayer has acquired, by investment, any interest in the oil in place, and secures, by any form of legal relationship, income derived from the extraction of the oil, to which he must look for a return of his capital.*" *Ibid* at 557. Five years later, the Court in Helvering v. Bankline Oil Co., 303 U.S. 362 (1938), reaffirmed the test laid down in Palmer and added:

"*But the phrase 'economic interest' is not to be taken as embracing a mere economic advantage derived from production, through a contractual relation to the owner, by one who has no capital investment in the mineral deposit.*" *Ibid.* at 367.

In addition, the IRS adopted almost literally the language of Palmer and Bankline in the first regulations prescribed under *The Internal Revenue Act of 1939* in establishing the tests to be administratively applied in determining what interests in mineral deposits are entitled to the depletion allowance. See Treas. Reg. 103, 19.23 (m)-1, Aug. 23, 1939. See also Parsons v. Smith, 359 U.S. 215, 222-223 (1959).

46
43 Stat. 253 (1924).

47
Ibid. 43 Stat. 253, 270 (re: individuals); 43 Stat. 253, 284 (re: corporations). The net income limitation revision was explained by the Chairman of the House Ways and Means Committee as follows: "*The deduction for discovery of [sic] depletion is limited to 50 percent of the net income of the property depleted. This applies mostly to cases of discovery of oil wells. At present a deduction for discovered [sic] depletion may be as great as the entire net income on the property depleted, and I have known instances where companies actually advertised that they could make a distribution of their dividends, without paying any corporation tax.*" [65 Cong. Rec. 2429, (1924)]

48
S. Rept. No. 398, 68th Cong., 1st Sess. (1924).

49
The Supreme Court held that under §234(a)(9) of *The Revenue Act of 1918*, and the regulations thereunder, bonus and royalties received by the lessor of an oil lease, after deductions allowed by the Act, were taxable income of the lessor.

Senate Hearings of 1925

In 1925, the Select Senate Committee on Investigation of the Bureau of Internal Revenue held extensive hearings concerning the administrative practices of the Bureau. In these hearings the Committee also studied the problems with the allowance for discovery depletion. The committee report devoted over 100 pages to the discovery depletion allowance, concluding that the allowance was too vague, difficult to administer, and was not accomplishing the purposes for which it was enacted, and thus should be legislated out of existence.[50]

The discovery depletion allowance required that each well be valued by at least one expert. The government, as well as the taxpayers, were incurring great expense to value producing properties for purposes of discovery depletion. While the government had maintained a large force of engineers for more than 10 years to determine property values, it was estimated that the taxpayers had borne ten times the expense incurred by the government. Most small taxpayers were unable to secure adequate depletion under the discovery method because they could not afford to employ the experts necessary to determine proper valuation.[51] These factors led to a significant change in the nature and extent of the allowance for depletion.

The Revenue Act of 1926

The Revenue Act of 1926 [52] created a completely new method for measuring the depletion of the primary capital assets of a petroleum extraction firm. Congress wishing to avoid the inadequacies of the first five percent depletion limitation and the administrative complexities and perceived abuses of discovery depletion, created a new allowance called *percentage* depletion.

Percentage depletion is a flat statutory rate of depletion equal to 27.5 percent of the gross income from the property to be depleted. The 50 percent net income limitation still applied. As the legislative history of this provision indicates, the figure of 27.5 percent was the result of past experience and political compromise, and was guided also by the fact that a petroleum extraction firm must look to the sale of its primary capital assets to generate revenue to continue operations.

Murphy Oil Co. v. Burnet, 287 U.S. 299 (1932). Furthermore, the Court found that §234(a)(9) and the regulations thereunder required depletion allowances upon bonus and royalty payments received by the lessor of mineral lands, sufficient to provide for a return in full of his invested capital. Bankers Coal Co. v. Burnet, 287 U.S. 308 (1932). Both of these cases relied upon Burnet v. Harmel 247 U.S. 103 (1932), decided four weeks earlier. The Harmel case, which involved *The Revenue Act of 1924*, held that income received by the lessor from an oil and gas lease, whether by way of an initial bonus or as royalties on the oil and gas subsequently produced by the lessee, was taxable under *The Revenue Act of 1924*, not as gain from the "sale" of capital assets, but as ordinary income. 247 U.S. at 105, 112.

50
Investigation of the Bureau of Internal Revenue, S. Rep. No. 27, 69th Cong., 1st sess. 3-4 (Confidential Committee Print, 1926). A summary of the findings in the report read as follows: *"It is very clear that the purpose of the provision for discovery depletion was to stimulate prospecting for new deposits of mineral and oil, yet the allowance of discovery depletion is not confined to the taxpayers who discover new deposits of mineral or oil...but is allowed to taxpayers who develop discoveries made by others, and upon deposits known to exist prior to March 1, 1913.*

"Analytic appraisals, which determine values to be depleted by discounting estimated expected profits, are too elastic and leave too much to the judgment of individual engineers to be suitable for taxation purposes. An amendment of the law is required to permit substitution of a more suitable method."

51
Reports to the Joint Comm. on Internal Revenue Taxation from its Staff Pursuant to §1203(b)(6), *The Revenue Act of 1926*, 71st Cong., 1st sess., Preliminary Report on Depletion, pt. 8, 8 (Comm. Print, 1930).

52
44 Stat. 9 (1926).

The House Ways and Means Committee made only minor changes in the depletion provisions of the bill, H.R. 1, which it reported.[53] It was the Senate Finance Committee that created the new percentage depletion allowance. The proposed depletion rate was 25 percent of the gross sales value of oil and gas at the wellhead.[54]

Debate was extensive in the Senate [55] and Senator Reed of Pennsylvania explained the need for the new provision as follows:

"I hope I have explained to the Senate how this present method of calculating depletion in oil wells is really a combination of uncertainties. The factor of error that is possible in either of those elements is intensified by the fact that we are multiplying one uncertainty by another....So we are trying, by the Finance Committee amendment, to get away from those uncertainties and to adopt a rule of thumb which will do approximate justice to both the Government and the taxpayer.

"When we come to calculating the income of a man who owns an oil well, we have to take into account the fact that the capital is constantly disappearing, that it is being depleted by the flow of the oil or gas ...Obviously, in calculating the oil well owner's income tax, we have, first, to make a deduction from his gross income for the amount by which this capital is being returned to him in this form which we call depletion...

"Ever since the early war days Congress has followed the policy of allowing what they call discovery value for both oil and gas wells and for minerals. It is perfectly obvious that if I buy an acre of land in the Rocky Mountains and pay $10 an acre for it, and then, by hard work, discover a rich deposit of gold on it, the calculation of my depletion on the original $10 basis would not allow me any adequate return for my real capital. So, in allowing what is called discovery value, Congress and the Bureau have tried to get at the real but the unknown value of the property owned by the taxpayer." [56]

The Senate debated whether a proposed 25 percent allowance would aid or injure the small independent producer. This prompted Senator Neely of West Virginia to express the hope that the bill would be amended to protect the small producers.[57]

Drawing on earlier testimony of the Treasury department, Senator Goff of West Virginia stated:

"...as far as Treasury can now determine, a fair depletion allowance, an allowance that does not confiscate the capital investment and in the interest of the Treasury, is from 35 to 37 1/2 or 40 percent; clearly a 25 percent depletion from the gross income is not sufficient to preserve intact the capital account. If we do not have at least 35 percent—and 40 percent would be better—then the capital account is invaded; and the

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H. Rept. No. 1, 69th Cong., 1st Sess. (1925).

54
S. Rept. No. 52, 69th Cong., 1st Sess. (1926). The report stated that *"The administration of the discovery provision of existing law in the case of oil and gas wells has been very difficult because of the discovery valuation that had to be made in the case of each discovered well. In the interest of simplicity and certainty in administration your committee recommends that in the case of oil and gas wells the allowance for depletion shall be 25 per cent of the gross income from the property during the taxable year. The provision of existing law limiting this amount to an amount not in excess of 50 per cent of the net income of the taxpayer from the property is retained." Ibid.* at 17-18

55
67 Cong. Rec. 3761-3778, 69th Cong. 1st Sess. (1926).

56
Ibid. at 3762.

57
Ibid. at 3763.

tax, instead of being a tax reasonably levied, is a tax to confiscate the capital invested, and therefore discourages the reinvestment of capital in discovery oil production." 58

Senator Goff offered an amendment on the Senate floor providing for either a 35 or 40 percent allowance depending upon the relation of operating expenses to gross income during the year. It was defeated.[59] Senator Neely proposed a flat 35 percent rate, but it was also defeated.[60] He then proposed 30 percent which was adopted.[61] In conference, the House receded with an amendment establishing 27.5 percent as the applicable depletion rate for oil and gas, a seeming compromise from the Senate bill's 30 percent depletion rate. [62]

In discussing the new 27.5 percent depletion allowance created by the 1926 Act, the Supreme Court noted in Helvering v. Producers Corp.[63] that:

"*Congress has recognized in fairness there should be compensation to the owner for the exhaustion of the mineral deposits in the course of production....But to appraise the actual extent of depletion on the particular facts in relation to each taxpayer would give rise to problems of considerable perplexity and would create administrative difficulties which it was intended to overcome by laying down a simple rule which could be easily applied. To this end, the taxpayer was permitted to deduct a specified percentage of his gross income from the property.*" 64

Legislative History: 1926–1969

There were few substantive changes in the percentage depletion allowance between its inception in 1926 and its eventual phaseout starting in 1969. However, there were numerous debates over the nature and proper role of *depletion.*

The Revenue Act of 1934 made no change in the depletion law except to amend §114(b)(4) to require a new binding election on the part of taxpayers as to the method of determining their depletion allowance. Despite this relatively minor change there were still significant debates on the efficacy of depletion as a capital recovery mechanism in hearings before the House Ways and Means Committee. These hearings were largely concerned with the 1933 report of its Subcommittee on Prevention of Tax Avoidance, 73rd Cong. 2nd Sess. (Comm. print, 1933), which had recommended a flat 25 percent reduction in the depreciation and depletion deductions for the years 1934 to 1936.[65]

58
67 Cong. Rec. 3764, 69th Cong., 1st Sess. (1926).

59
67 Cong. Rec. 3775, 69th Cong., 1st Sess. (1926).

60
This proposal was defeated by a vote of 32 to 31 with 33 senators not voting. *Ibid.* at 3776.

61
This passed by a vote of 35 to 29 with 32 senators not voting. *Ibid.* at 3777. The Senate Finance Committee amendment to the House bill, as amended, passed by a vote of 48 to 13 with 35 senators not voting. 67 Con. Rec. 3778 69th Cong., 1st Sess. (1926).

62
H. Rep. No. 356, 69th Cong., 1st Sess. (1926).

63
303 U.S. 376, 381 (1938).

64
See U.S. v. Dakota-Montana Oil Co., 288 U.S. 459, 461 (1933). See also Helvering v. Twin Bell Syndicate, 293 U.S. 312, 321 (1934).

65
The representatives of the oil and mining industries appeared to oppose the proposals to limit the allowance for depletion. The Treasury position that depletion represented a subsidy for a special class was denied. An oil witness stated that discovery depletion was not a war-time measure because *The Revenue Act of 1918* was not passed until February 24, 1919, four months after the close of hostilities and the provision was subsequently reenacted in 1921 and 1924. [Testimony of John Cullen, representing the Mid-Continent Oil and Gas Association, Tulsa, Oklahoma Hearings before the House Committee on

In 1942, Secretary of the Treasury Morgenthau recommended to the House Ways and Means Committee the elimination of percentage depletion, in order to increase wartime revenues.[66] In response to the Secretary's statement former Senator Gore of Oklahoma explained the reason behind the depletion provision as follows:

"Take a wholesale grocer who buys...100,000 barrels of flour. He pays $3 a barrel and he sells it for $4 a barrel. The difference between the $300,000 that he pays and the $400,000 that he takes in represents gross profit. From that he subtracts his expenses, and so arrives at his net income. You lay a tax on his net income. You do not undertake to lay a tax on the $300,000 that he receives for the flour which merely represents what he paid for the flour. That is his invested capital. That is what he is doing business on.

"In the first place, Congress would have no disposition to tax the return of the $300,000, and in the second place, Congress has not got the power to do it, if it had the disposition. That would be a tax on capital, not a tax on income, and under the Sixteenth Amendment, Congress only taxes income. You cannot tax capital. A tax on any form of capital can only be imposed in accordance with the rule of apportionment, and... That is the point." [67]

The Revenue Act of 1954

By 1954, percentage depletion had been extended by the Congress to virtually every category of exhaustible resources and some renewable resources. The statutory depletion rates were 27.5 percent for oil and gas, 23 percent for sulfur and 15 percent for metals.[68]

In order to raise $300 million in tax revenues, Senator Williams of Delaware

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Ways and Means on the Revenue Revision of 1934, 73rd Cong, 2nd sess., pp. 245 ff (1934)]

The same witness stressed the necessity of permitting the oil and gas industry to set aside a part of its profits as reserve for the replacement of oil produced. He argued that no other business was as hazardous as the production of oil.

66

After pointing out that percentage depletion resulted in allowances in excess of cost depletion, Secretary Morgenthau stated:

"One of the reasons asserted in behalf of percentage depletion for oil and gas properties is that it stimulates exploration for such properties. If this is a proper objective, it would be better achieved by a special depletion allowance to those who do explore without indiscriminate extension of the same favor to all owners." Heaings Before the House Committee on Ways and Means on the Revenue Revision of 1942, 77th Cong., 2nd sess. 9 (1942)

Representative Disney of Oklahoma and Representative Buck of California expressed concern over the effect of the proposal to eliminate percentage depletion on stripper wells. Representative Disney was of the opinion that stripper wells would be forced out of production; he pointed out that, once abandoned, they cannot be restored to productivity. Secretary Morgenthau agreed that strippers might be hurt by the Treasury proposal but suggested a direct Government subsidy to help them, if necessary. *Ibid.* at 34-35.

67

Hearings Before the House Committee on Ways and Means on the Revenue Revisions of 1942, 77th Cong., 2nd sess. 1015 (1942).

68

In order to prevent uncertainty and controversy, the Act provided a category of nonmetallic minerals which was to include all other minerals not specifically listed in the bill, other than soil, sod, dirt, turf, water, or mosses or minerals from sea water, the air, or similar inexhaustible sources. In reviewing the 1954 House bill, Mr. Reed of New York, the Chairman of the Ways and Means Committee stated:

"Under existing law, percentage depletion has been granted to 56 classes [of] nonmetallic minerals. Many of the classification *have been inexact and there had been much uncertainty and controversy in this area. The bill clarifies existing law and provides a grouping which is administratively more feasible and competitively more equitable. Under this revision there are a few increases, but no reductions, in the rates of percentage depletion allowance by the present law and regulations."* 100 Cong. Rec. 3424, 83rd Cong., 2nd Sess., (1954).

proposed to cut the oil and gas depletion rate from 27.5 percent to 15 percent. Whereupon, Senator Neely of West Virginia and eight other senators testified to the importance of the oil and gas depletion allowance. Senator Neely eloquently explained and reaffirmed the nature and purpose of the 27.5 percent depletion rate which he had written 28 years before:

"During the latter part of the year 1925 and the early days of 1926 informed men of vision warned the Nation that its supply of oil was being rapidly diminished and that it would, in the reasonably near future, be exhausted. It was then estimated that our total oil reserves amount to only 8,500,000,000 barrels. Patriotic men in high places urged the conservation of this vital resource and even recommended that it be nationalized in order that it might be conserved to the limit of possibility.

"At that time it was daily becoming more and more difficult to find oil. Its discoveries in 1922, 1923, and 1924, averaged approximately a half billion barrels a year. Multitudes of venturesome patriotic tireless men were spending their lives and their fortunes vainly searching for more oil. At last the prudent declined to spend their days and their capital in the burdensome, bankrupting, hazardous hunt for oil.

"A diligent Congress recognized the Nation's peril in this vital matter and proceeded to provide the necessary protection against it by adopting the depletion allowance provision under which oil operators, who were fortunate enough to succeed could eventually regain their capital investment. The effect of the adoption of the amendment was immediate and amazingly beneficial. As a result of its operation, a foundation was laid for accomplishments by virtue of which the United States is today the last and only effectual barrier to communistic conquest and enslavement.

"From 1926 to 1931 the newly discovered oil averaged over two billion barrels a year-300 percent more than the average discoveries of 1922, 1923, 1924.

"The provision of the law which the Senator from Delaware is striving to cripple, rendered it possible for America to supply the oil that enabled her and her allies to win the Second World War. That war made more than a fourfold increase in the demand upon our oil resources and production. Nevertheless, because of the incentive afforded by the depletion allowance provision, we now have more than 3 times 8,500,000,000 barrels of reserve oil, of which we knew 28 years ago ....

"In justification of the present depletion allowance provision, let me remind the Senate that in this country last year it was necessary to drill six and six-tenths oil wells in order to obtain one producer, and that our average cost of drilling a producer oil well in 1953 was more than 17 times as much as it was before the Second World War." [69]

Senator Daniel of Texas addressed Senator Williams' chief reason for the proposed rate reduction, *i.e.*, that it would provide the Treasury about $300 million additional revenue. Senator Daniel argued that a reduction in the rate for oil and gas would result in less tax revenue:

"I know that the chief interest of the Senator from Delaware is in producing additional revenues which are badly needed by the United States Treasury. Has it not occurred to him that revenues may be decreased rather increased by reducing the allowance? According to a letter from the Secretary of the Treasury dated April 22, 1954, and placed in the Record by Senator Williams on the same day, page 5408, 'past estimates of the direct revenue effects of this reduction in

69
100 Cong. Rec. 9302, 83rd Cong., 2nd Sess. (1954)

depletion allowance have been of the order of $200 million. However, the Secretary adds, 'These estimates make no allowance for the indirect adverse effects which might arise from the reduction in activity or for other reasons'" 70

The Williams' amendment to reduce the oil and gas depletion was rejected.[71]

The Tax Reform Act of 1969

The Tax Reform Act of 1969 began the eventual phaseout of the percentage depletion deduction. The House bill proposed to reduce percentage depletion for oil and gas production from 27.5 percent to 20 percent and eliminated the use of percentage depletion on foreign oil and gas production by U.S. taxpayers. The Senate Committee on Finance responded with a reduction in the depletion rate to 23 percent. In conference committee the statutory rates on oil and gas were reduced to 22 percent, and enacted into law. [72]

This Act was the beginning of the U.S. alternative minimum income tax system. It also provided that tax liability would be based, in part, on the amount of *percentage depletion* taken in excess of a producer's cost basis in a property.

The Energy Tax and Individual Relief Act of 1974 (Proposed)

In response to the Arab oil embargo and escalating oil prices, the House attempted to pass a bill which would impose a windfall profit tax on oil producers and phase out percentage depletion for oil and gas.[73] The bill proposed to reduce the depletion rate for oil and unregulated gas from 22 percent to 15 percent for 1974 and, in 1975, to remove percentage depletion entirely.[74]

The committee bill provided three exemptions from the phaseout: [75]

- A *small producer exemption* that applied to the first 3,000 barrels of a taxpayer's average daily production and was available to all taxpayers regardless of average daily production.
- A *stripper well exemption* for all domestic wells whose production of crude oil for any calendar month averaged 10 barrels per day or less. The exemption for oil could be used regardless of the volume of natural gas produced from the same well.
- An exemption for Alaskan North Slope production.

A taxpayer was to elect whichever exemption was of most benefit to him. However, the exemption applied only to the phaseout provision and was not to postpone the rate reduction to 15 percent. The bill also proposed removing the 50 percent net income limitation for oil and gas wells. The committee recognized that the limitation discouraged secondary and tertiary recovery processes, developmental drilling, and high-cost low-volume wells. Also, it recognized that increasing the limitation to 100 percent of net income would encourage added

70
100 Cong. Rec. 9309 83rd Cong., 2nd Sess. (1954). It should be noted that current revenue estimation procedures also do not estimate the future increases in tax receipts that occur from a given response to changes in income tax provisions.

71
100 Cong. Rec 9319 83rd Cong., 2nd Sess. (1954).

72
Sec. 501, Pub. L. No. 91-172, 83 Stat. 487 (1969).

73
H. R. 17488: Energy Tax and Individual Relief Act of 1974, House Ways and Means Committee Report. H. Rept. No. 93-1502, 93rd Cong., 2nd Sess. (1974).

74
Ibid. at 45.

75
Ibid. at 45-50.

exploration and development.[76] The proposal was never enacted.

The Tax Reduction Act of 1975

The Tax Reduction Act of 1975[77] eliminated the allowance for percentage depletion for integrated oil and gas producers and severely limited its use by all other producers. The debate on repealing the depletion allowance demonstrated rising negative Congressional sentiment because of soaring oil prices and profits.[78] In the House, discussion centered on an amendment presented by Representative Wilson of Texas to exempt from the repeal of percentage depletion 3,000 barrels a day of an *independent* producer's production. Opponents of the amendment denied the industry's need for percentage depletion, citing the high price of oil, tax loopholes, and record industry profits. Representative Drinan of Massachusetts spoke as follows:

"I would now like to turn, Mr. Chairman, to an extremely important amendment which is being offered to the Tax Reduction Act. My colleague from Pennsylvania, Mr. Green, has offered an amendment which would eliminate the 22 percent oil and gas depletion allowance effective January 1, 1975....

"We have watched oil prices skyrocket in the past year while profits of oil companies have soared. Major oil companies have increased their annual profit from $2.9 billion in 1968 to $7.3 billion in 1973. In addition, the next earnings of the 10 largest oil companies for the first half of 1974 are 148 percent greater than the same period last year. In the face of these statistics, providing the energy producers with this continued tax loophole simply does not make good sense." 79

During these debates it was recognized that the depletion deduction was primarily a capital cost recovery allowance designed for industries that produce exhaustible finite resources. Representative Johnson of Pennsylvania recounted the history and purpose of the depletion allowance as follows:

"This depletion allowance, when it was first enacted, was to encourage development, but its foundation is based on the fact that oil properties are a capital asset. If one sells the oil property, one gets a capital gain on it and one pays only up to 50 percent of the profit. However, if one produces oil piecemeal and without the depletion allowance, one pays ordinary income tax on it. In other words, one is selling a nonrenewable capital asset and not getting the benefit of the capital gain. That is the reason for the oil depletion allowance in the first place." 80

Representative Johnson also acknowledged the effect the percentage depletion deduction had on marginal production and new exploration.[81]

76
Ibid. at 55.

77
P.L. 94-12, 89 Stat. 26 (1975).

78
The House bill, H.R. 2166, proposed to repeal percentage depletion for all oil and gas, except fixed contract and regulated gas, produced on or after January 1, 1975. S. Rept. no 94-36, 67, 94th Cong. 2nd sess. (1975).

79
121 Cong. Rec. 4622, 94th Cong., 1st Sess. (1975).

80
121 Cong. Rec. 4616, 94th Cong., 1st Sess. (1975).

81
Representative Johnson further stated:
"During the last 20 years, the fields have not been producing as much as they should, as the price of oil has been too low, and the cost of production too high. Those who have stayed in business were able to do so because of the depletion allowance. However, the recent increase in the price of oil, plus the depletion allowance, has created great activity, and many new well loca-

The Act created a new section of the Internal Revenue Code that defined which type of production or producers qualified for percentage depletion.[82] A limited allowance for percentage depletion was provided to the following categories of oil and gas production:

- regulated natural gas;
- natural gas sold under a fixed price contract;
- certain oil and gas production of independent producers; and
- certain production of royalty owners.[83]

Independent producers and the royalty owners were further limited in the use of percentage depletion to 2,000 equivalent barrels of oil and gas production, which phased down to 1,000 in 1980.[84] Also, *The Tax Reduction Act* provided a phased-in rate reduction from the 22 percent rate passed in the 1969 Act to the current rate of 15 percent and eliminated percentage depletion for proven properties transferred after passage of the Act. Depletion rates declined to 15 percent in 1984, and the Act further limited the percentage depletion deduction to not more than 65 percent of taxable income.[85]

The Tax Reform Act of 1986

As noted in the White Paper, *The Tax Reform Act of 1986* made signifiicant changes in the nature and operation of the U.S. system of income taxation. However, it made only limited changes to the allowance for percentage depletion. *The Tax Reform Act* provided that percentage depletion would not apply to oil and gas lease bonuses, advance royalties, or other payments made without regard to actual production. This provision was in response to the Supreme Court's decision in Comm. v. Fred L. Engle, *et ux*.[86] The percentage depletion of bonuses had been previously

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tions have been staked out and much new drilling is planned. Marginal properties, heretofore unprofitable, have all of a sudden become attractive for exploration and as a result, 15 million barrels have been added to recoverable reserves, now estimated at 50 million barrels...

"If we want to help Project Independence, help President Ford in bringing this country to a sound energy solution, we should pass this 3,000-barrel exemption." 121 Cong. Rec. 4616, 94th Cong., 1st Sess. (1975).

82
The *Internal Revenue Code of 1954*, §613A.

83
Pub. L. No. 94-12, 89 Stat. 47, §501 (1975).

84
An independent producer was defined by the Act to be a person or a business entity who is not engaged in retailing or refining. A retailer is a taxpayer who sells oil or natural gas, or any product derived from oil or natural gas through retail outlets in excess of $5,000,000 annually. A refiner is a taxpayer who engages in refining of more than 50,000 barrels of crude oil on any given day during the year.

85
The additional limitation equates to 65 percent of the taxpayer's total taxable income computed without regarded to: 1) the depletion deduction; 2) any net operating loss or capital loss carry back; 3) any trust distributions and 4) before 1986, the individual's reduction by the zero bracket amount.

86
In Comm. v. Fred L. Engle, *et ux.*, 464 U.S. 206 (1984), the Supreme Court ultimately concluded that actual production was not a prerequisite for depletion under section 613A of the Internal Revenue Code of 1954, as amended, and, although it did not opine as to when the deduction was allowable, concluded that bonuses continued to be eligible for percentage depletion. J.L. Houghton, Arthur Young's Oil and Gas, Federal Income Taxation 59-60 (1987).

The court also stated that: *"Section 613A clearly provides that income attributable to production over a certain level will not be eligible for percentage depletion. But nothing in the statute bars percentage depletion on income received prior to actual production (464 U.S. 224)...it becomes clear to us that Congress did not mean...to withdraw the percentage depletion allowance on lease bonus or advance royalty income arising from oil and gas properties."* *Ibid*, 223-24.

reviewed and approved by the Court as a payment from which the investor obtained his return of capital.[87] The Court found that, in light of the history of the allowance on lease bonuses and advance royalty, Congress must specifically provide for the removal of these items from percentage depletion.

87
Palmer v. Bender, 287 U.S. 551 (1933) and William E. Herring v. Comm, 293 U.S. 322 (1934).

Section Three:

Graphic Summary of Quantitative Analysis

by
Goodman, Gordon and Youngblood

Explanation

The following case studies are graphic representations of the after-tax cash flows generated by the statistically *"average"* U.S. geological prospect for each type of taxpayer noted. Present values are used throughout the study to account for the time value of money. Additionally, where noted, "expected" present values are also used. The use of *expected present values* allows the cash flow streams to be risk weighted to account for the geological risks of exploratory failure.

In reality, only a small fraction of exploratory prospects drilled in the U.S. are successful. The national average is about 14%. Therefore, companies must make their investment decisions based on economics that reflect the risk that a given well will be a dry hole, and that the company's entire investment will be lost.

The risk weighted or expected economics represent a more realistic estimate of the results of drilling a typical geological prospect and they are used by most companies and investors to arrive at an investment decision. Consequently, the structure, operation and competitiveness of the U.S. tax and fiscal system is best viewed on the basis of expected cash flows and expected after-tax returns to the investor and society.

Bar Graphs

The bar graphs represent (1) the wealth that is added to U.S. society, (2) the increase in financial claims and tax receipts that are generated to the Federal and state governments, and (3) the net revenues that flow to the corporate investor/taxpayer. Each cash flow, including the wealth added to U.S. society, is converted into its present value using a discount factor of 15% and is thereafter weighted by the exploratory and developmental risks incurred. The statistically average geological prospect used for these charts assumes that the exploratory dry hole risk on the first well is 75%. The national average dry hole rate for "rank wildcat" exploratory prospects is approximately 86%.

Pie Charts

The pie charts show the distribution of the net revenues from the prospect after the costs of the project are deducted as allowed by the U.S. tax and fiscal system. This chart assumes that the prospect is developed despite a negative expected value to the investor/taxpayer.

These pie charts also assume that the investor/taxpayer is successful on the first exploratory attempt and, therefore, incurs no exploratory risks. Thereafter, the investor/taxpayer drills 10 developmental wells, of which 3 are dry holes. The national average developmental dry hole risk is approximately 25% to 35%.

Purpose of Analysis

The purpose of this analysis is to demonstrate graphically the absolute and relative impacts of the financial burdens that are imposed on domestic petroleum resources by the current U.S. tax and fiscal system. This analysis differs from other quantitative analyses in several material respects.

First, the graphs demonstrate the total "expected" revenues that each member of U.S. society including the Federal government and the investor/taxpayer will receive from a typical prospect both with and without geological risks computed. The major claimants to the social wealth generated by U.S. petroleum resources are the Federal and state governments, the investor and the landowner. It should also be noted that increases in wealth to U.S. society are computed after payments to contractors, employees and suppliers.

Second, this analysis presents the results for each type of U.S. taxpayer and producer. The authors are not aware of any other quantitative analysis to demonstrate these differences in after-tax economics.

Next, it shows how and to what extent the relative financial burdens shift as a function of an investor's taxpaying position and as a function of field size (*i.e.*, total expected revenues), well depth (exploration and development costs), and future oil and gas prices. The authors are also unaware of any other analysis that demonstrates these relative findings.

Observations

Several observations are possible from this analysis.

First, an independent producer in a regular taxpaying position can *expect* a profit from a statistically average U.S. prospect while the same or a competing producer in an alternative minimum taxpaying position can *expect* a loss in a similar amount. However, an independent producer in an net operating loss taxpaying position can expect a loss on the same investment of twice the size. Similar results occur for integrated producers.

Second, the loss that can be expected by an independent producer in an alternative minimum taxpaying position will be higher than the loss that can be expected by an integrated producer in a regular income taxpaying position. Since over 75% of U.S. independent producers and over 65% of integrated producers fall within these taxpaying positions, this result is surprising and counterintuitive as it is generally perceived that independent producers are treated more favorably within the U.S. tax code.

Third, the total financial burdens on a statistically average U.S. geological prospect increase substantially as oil prices and field sizes decline and as well depths increase. Additionally, the economic impact of the alternative minimum tax increases substantially as prices, revenues and/or profitability decline. This compounds an already regressive structure of the U.S. tax and fiscal system. Consequently, the degree of regressiveness of the financial claims on U.S. natural resources increases both absolutely and comparatively under the alternative system of U.S. income taxation.

Last, the U.S. tax and fiscal system generally, and the alternative minimum tax specifically, discourage risk taking. Thus, the system distorts economic decision making, resulting in potentially significant losses in wealth to U.S. society. As shown in case studies 16 and 17, the risks that would be acceptable to an investor are substantially less than the risks that would produce increases in social wealth and therefore be acceptable to society. The differences in risks which are acceptable for investors and society are created by the structure and operation of the U.S. tax and fiscal system. This leads to the conclusion that changes in the structure of the U.S. system can produce significant increases in wealth to U.S. society.

Assumptions Used in Case Studies

Project start date:	1989
Well depth:	5441 feet (EIA statistical average).
Reserves discovered:	640,000 BOE-(80,000 BOE/well) (EIA statistical average).
Number of wells:	8 (1 exploratory, 7 development). Exploratory well is successful on the first attempt with a 75% risk of a dry hole and subsequently used as a production well; 3 out of ten development wells were dry holes.
Decline rate:	12.5% per year.
Oil share in reservoir:	80% oil; 20% gas.
Total of all royalties:	18.75% (includes all overrides etc.).
Tax rates:	Federal-34%; AMT-20%; State Severance-4.9%.
Social discount rate:	15% (same rate used as corporate "hurdle rate").
Lease acquisition costs:	$150,000 (includes G&G expenditures).
Crude oil prices:	EIA base case. Starting price of $16.33 per barrel of oil and $1.63 per Mcf of natural gas rising to $94.24 and $9.42. respectively over the life of the project

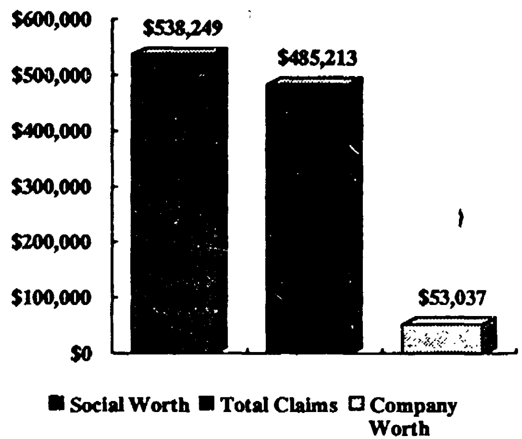
Case 1

Independent Producer

Regular Taxpayer

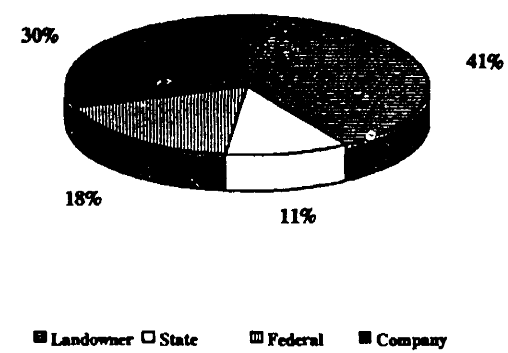
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



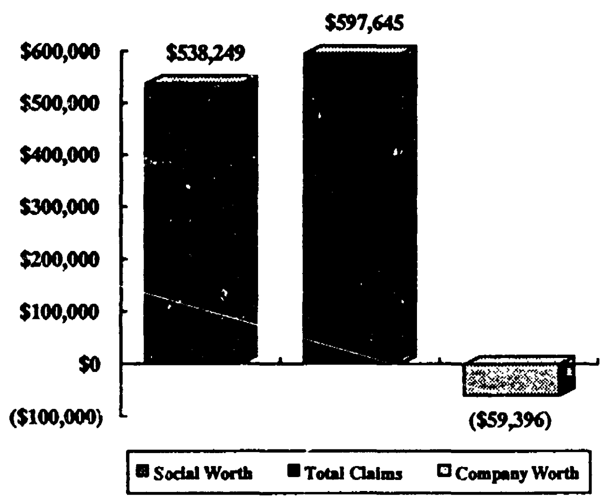
Case 2

Independent Producer

Regular Tax NOL

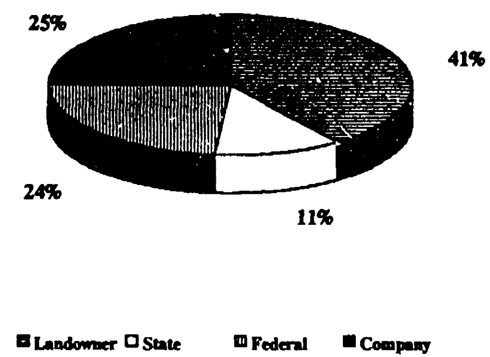
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



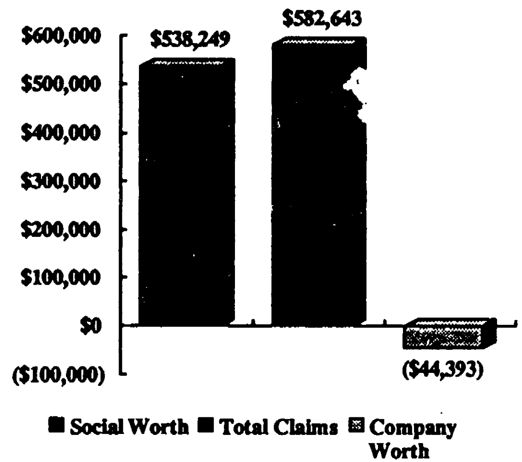
Case 3

Independent Producer

Alternative Minimum Taxpayer

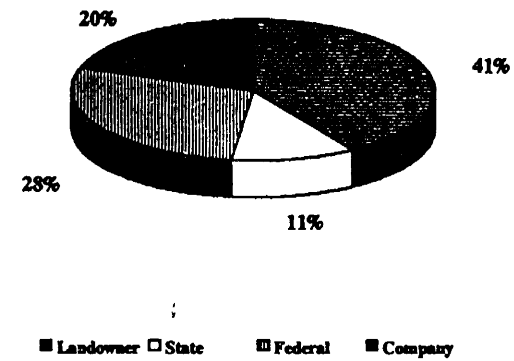
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



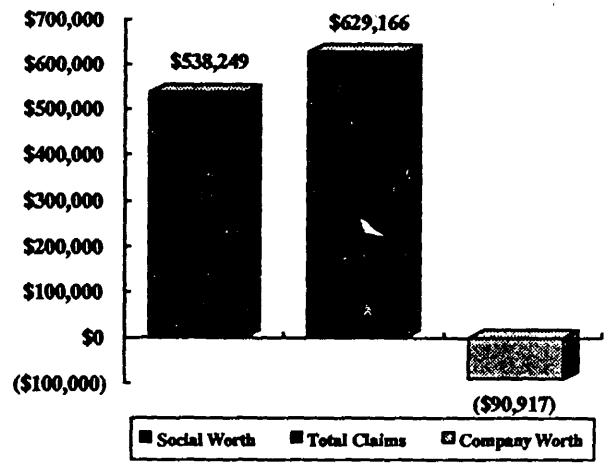
Case 4

Independent Producer

AMT NOL

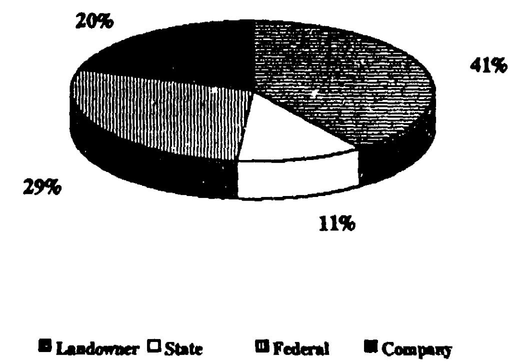
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



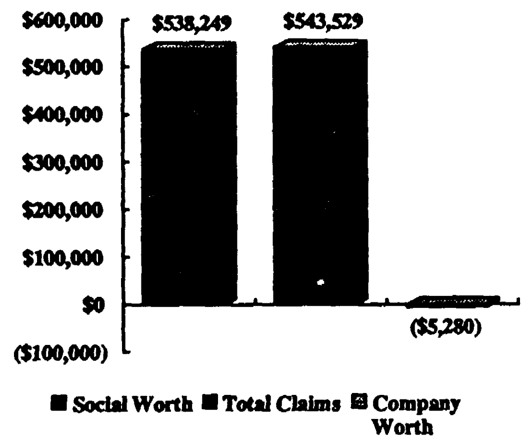
Case 5

Integrated Producer

Regular Taxpayer

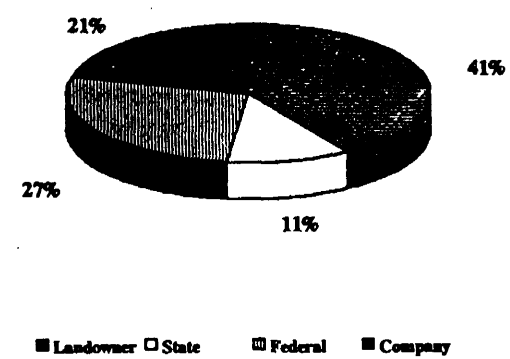
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



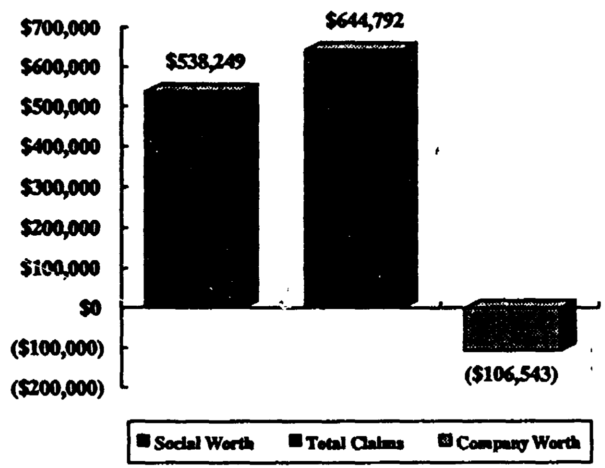
Case 6

Integrated Producer

Regular Tax NOL

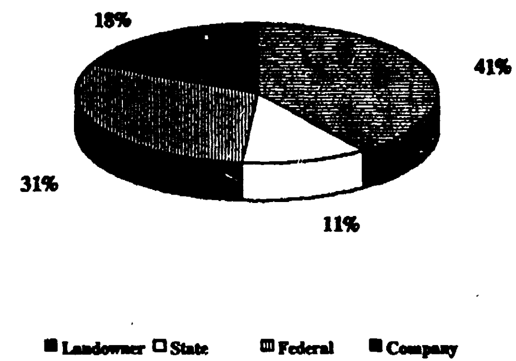
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



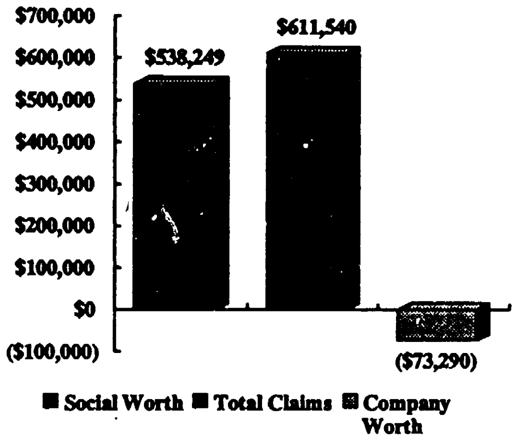
Case 7

Integrated Producer

Alternative Minimum Taxpayer

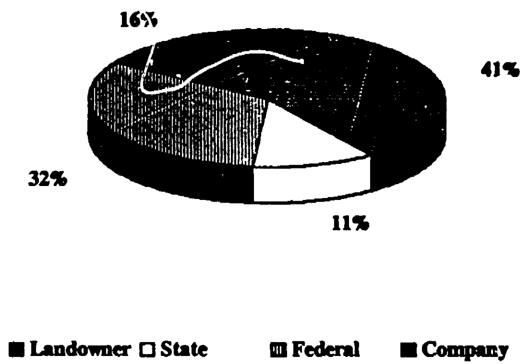
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



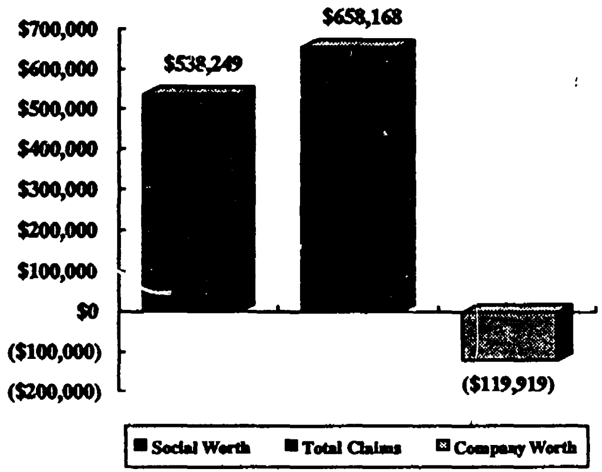
Case 8

Integrated Producer

AMT NOL

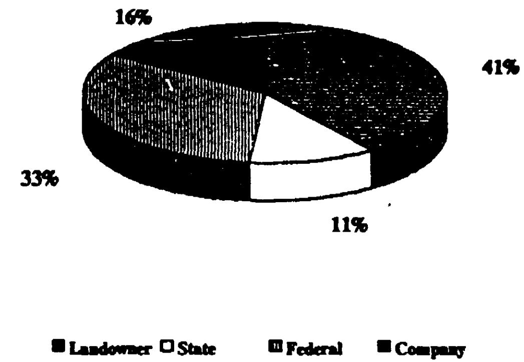
Risk Weighted Income

Discounted Expected Present Worth



Shares of Income

No Risk Prospect



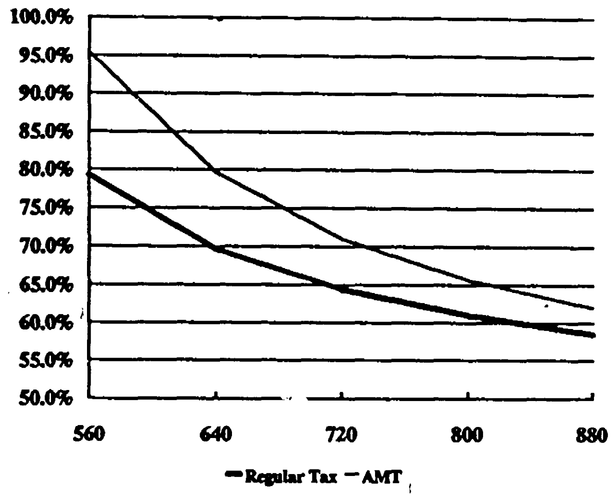
The Relationship of Total Tax and Financial Claims on U.S. Petroleum Extraction Investments to Changes in Reservoir Size, Well Depth, Prices and Geological Risks

Percentage Total Claims on E&P Projects

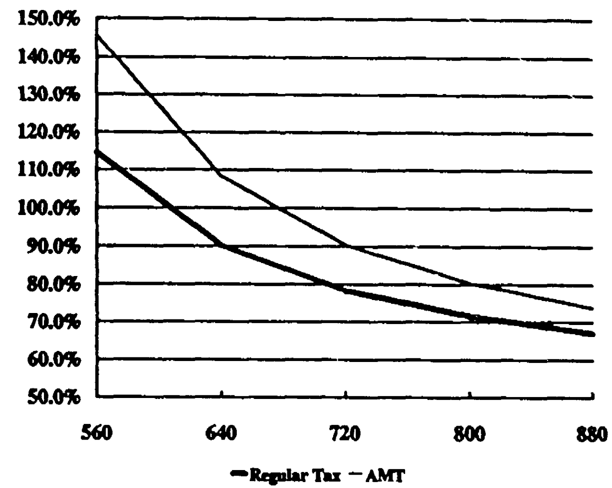
Independent Producer

As a Function of Field Size (Thousand Barrels of Oil Equivalent)

No Risk Case



Risk Weighted Case

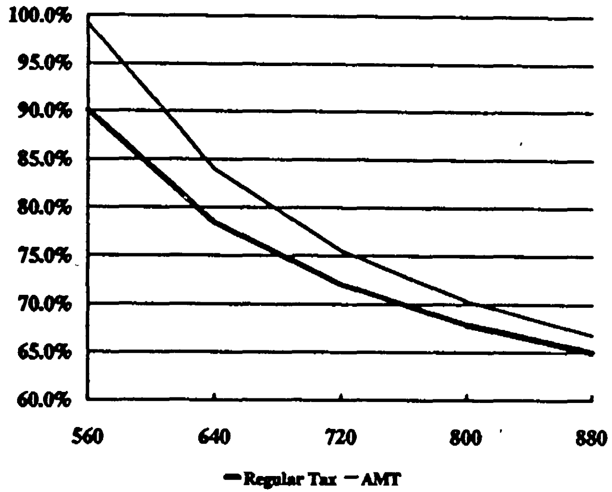


Percentage Total Claims on E&P Projects

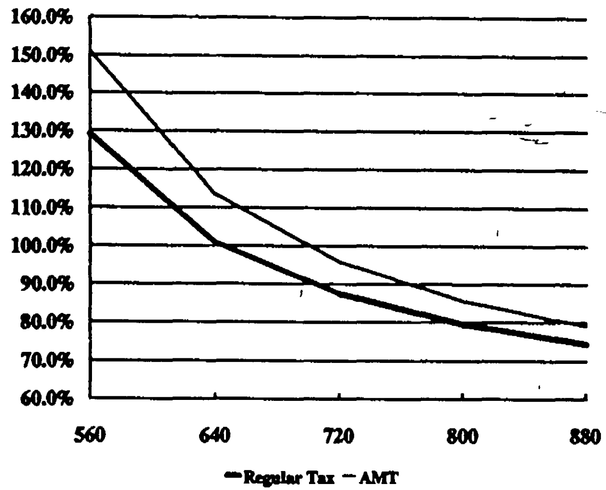
Integrated Producer

As a Function of Field Size (Thousand Barrels of Oil Equivalent)

No Risk Case

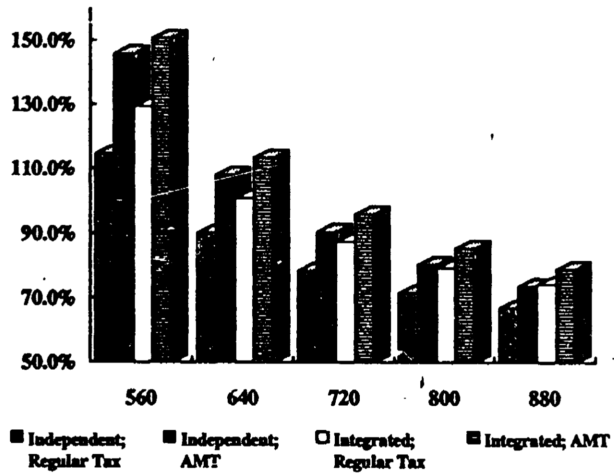


Risk Weighted Case



The Burden of Total Claims as Field Size Changes

As a Function of Taxpayer Type and Tax Status

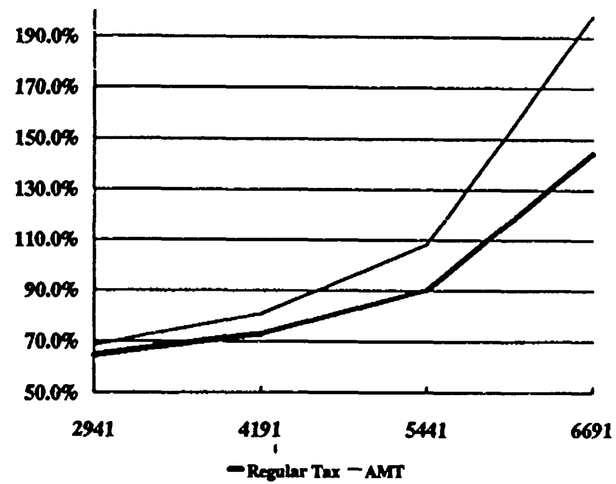


Note: Total burden is computed on a risk weighted basis and, therefore, reflects the expected burden on the prospect after factoring in the risk of failure. For all field sizes, an independent subject to the AMT bears the same or greater burden of total claims than an integrated producer subject to the regular income tax.

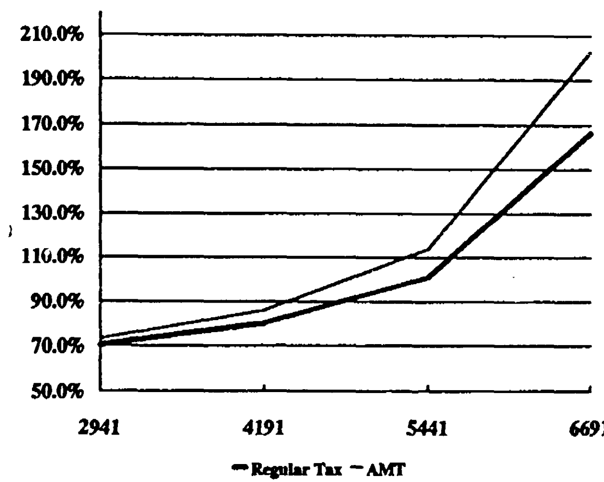
The Burden of Total Claims as Well Depth Changes

As a Function of Taxpayer Type and Status

Independent Producer



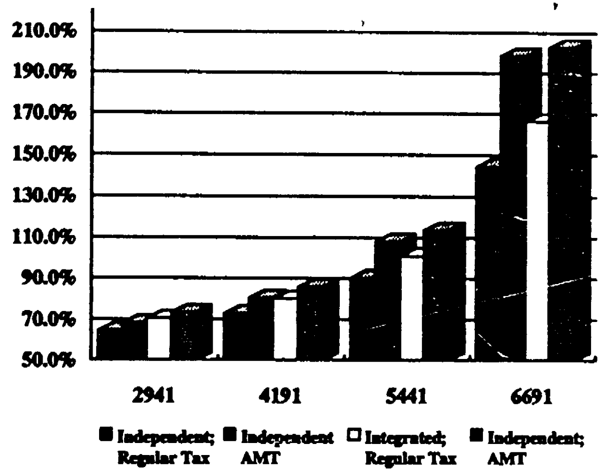
Integrated Producer



Note: Total claims are calculated on a risk weighted basis.

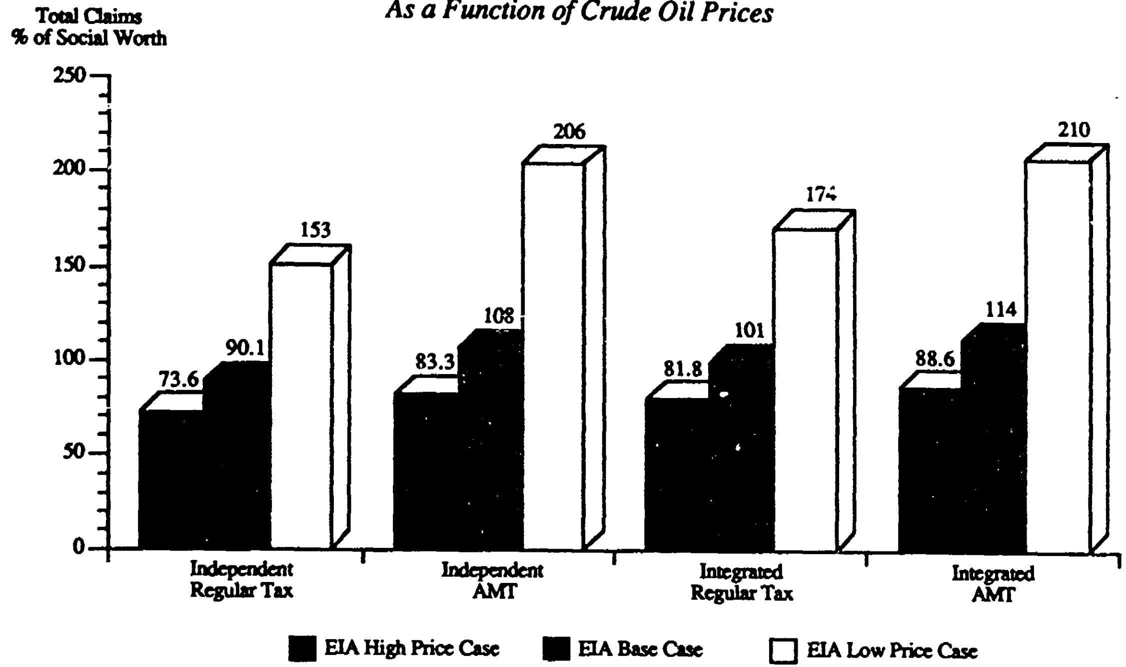
The Burden of Total Claims

As a Function of Well Depth and Taxpayer Type and Status



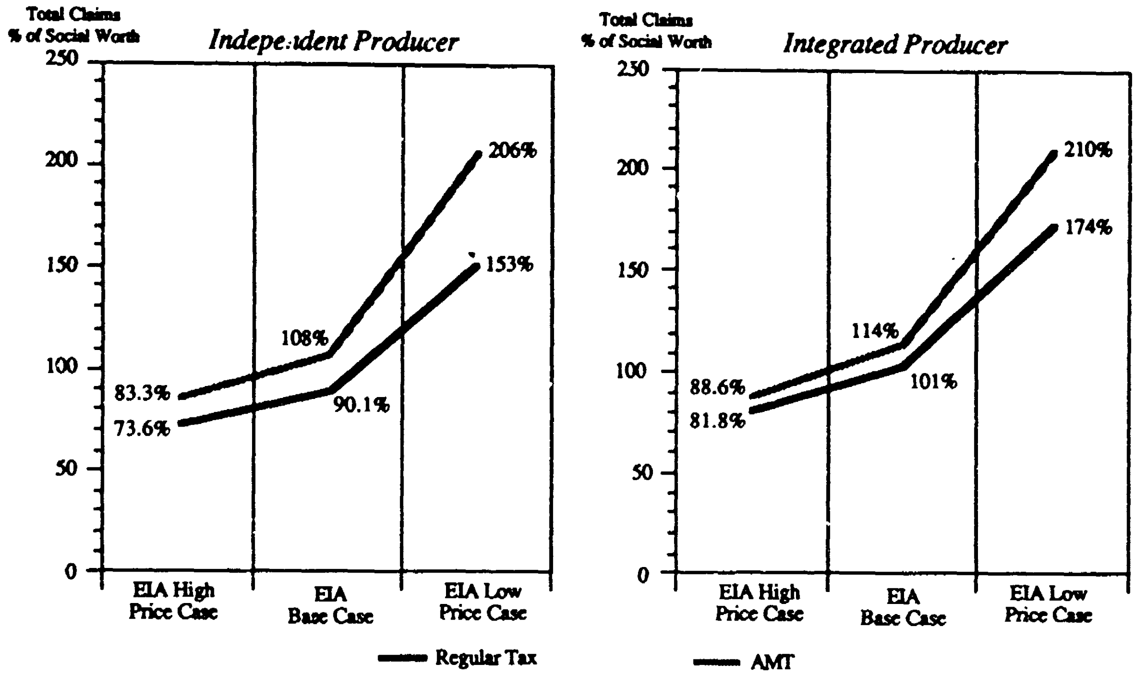
Total Claims on U.S. E&P Projects

As a Function of Crude Oil Prices



Note: Total claims are calculated on a risk weighted basis.

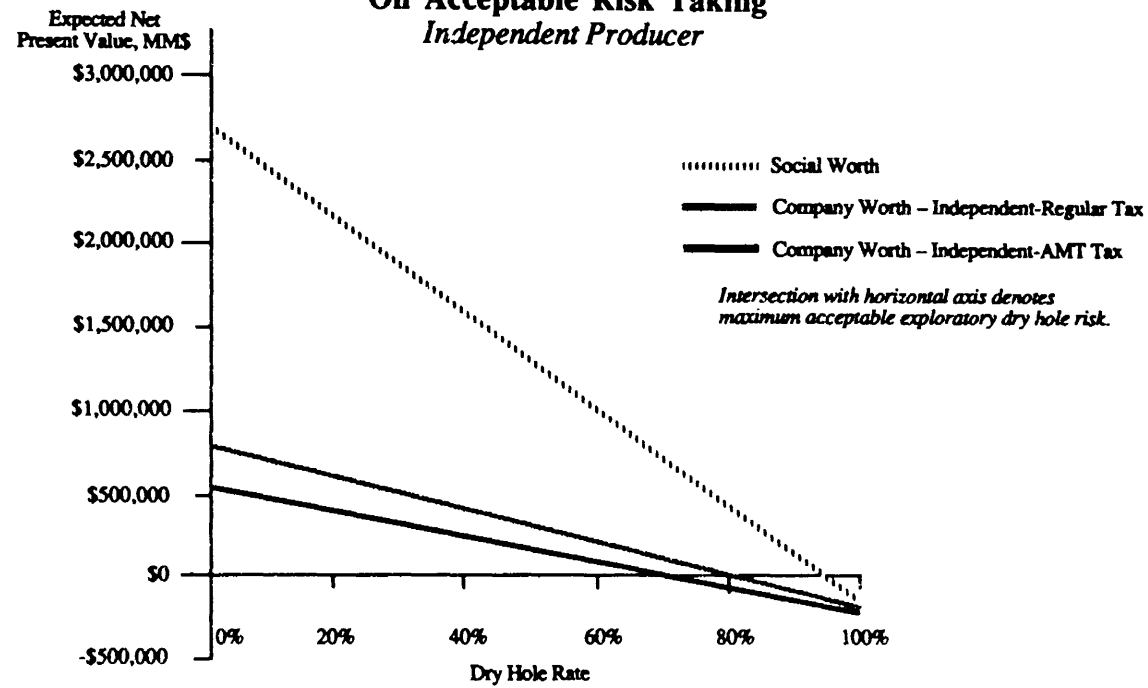
Total Claims on U.S. E&P Projects As a Function of Crude Oil Prices



Note: Total claims are calculated on a risk weighted basis.

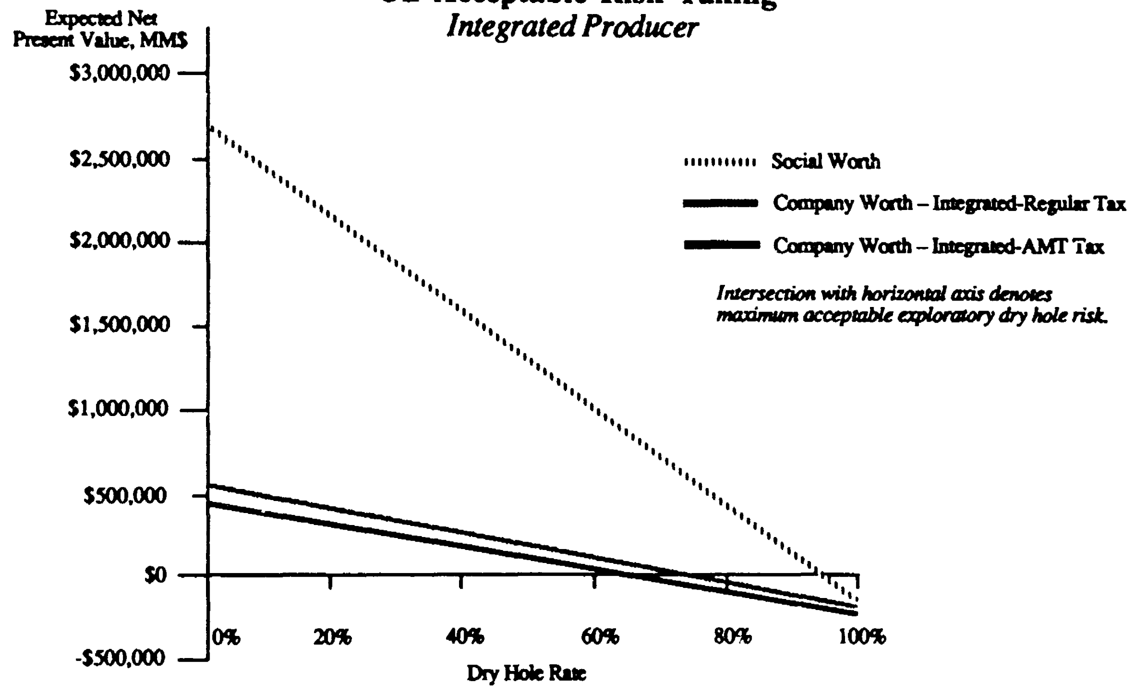
Effect of U.S. Tax and Fiscal System On Acceptable Risk Taking

Independent Producer



Effect of U.S. Tax and Fiscal System On Acceptable Risk Taking

Integrated Producer



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PREPARED STATEMENT OF STEPHEN C. LIPMAN

Union Oil Company of California (Unocal) offers the following comments on energy tax policy to the Subcommittee on Energy and Agricultural Taxation of the Senate Finance Committee. Unocal is an integrated earth resources company engaged in all aspects of energy production, both domestic and foreign. We support legislation to encourage domestic energy production.

The stage is being set for the next energy crisis. Imports of crude oil and petroleum products averaged 46 percent of demand in 1989 and, if current trends continue, they will reach the 50 percent benchmark this year. U.S. oil production is declining rapidly. It has already fallen from a 9.0 million barrel per day rate in 1985 to close to 7.0 million barrels per day in 1990 and now stands at its lowest point in 29 years.

Taking no action would be irresponsible. Yet, massive government intervention would be equally irresponsible. We should repeat neither the laissez-faire complacency of the 60's nor the costly crash programs of the 70's. Congress should strive to reduce the inherent uncertainty caused by foreign induced oil price volatility. Congress should also provide relatively inexpensive tax incentives to improve productivity and advance technology in ways that can make a meaningful difference in the long term.

The strategic petroleum reserve is one part of what should be a multifaceted effort to reduce uncertainty. Another part of that effort should be a variable import fee with a low trigger price to establish a floor price for oil. Setting the trigger price at the market price at the time of enactment would avoid serious economic distortion while still giving domestic energy producers a positive signal. Energy producers would benefit from more stable financial markets and would be more likely to develop marginal yield properties. At the same time, energy consumers would be encouraged to increase conservation efforts.

The President has endorsed tax incentives to stimulate domestic oil production. We agree. It is not likely we cduction decliproduction decline, but Congress should do more to slow it down This effort takes on even more significance in light of recent events: First, the President's June 26 announcement of a moratorium on offshore drilling, which will increase our dependence on foreign sources of crude oil. Second, ever expanding environmenta! requirements, make domestic exploration and production more expensive and mean less capital remaining for domestic exploration and development. Accordingly, all reasonable means must be adopted to increase domestic production and lessen the burden of the required environmental expenditures.

Increasing production requires adding new reserves to our domestic reserve base. A variable import fee keyed to a realistic oil price would provide a floor allowing energy producers the certainty necessary to invest in domestic sources of energy. There are five ways to increase domestic sources of energy: new discoveries, extension of existing fields, adding to the life of older stripper production, enhanced oil recovery techniques, and increased dtvrnative energy ernative energy sources.

The first, new discoveries, is largely beyond the scope of this hearing. Some of the nation's most promising frontier exploration areas, the outer continental shelf and northern Alaska, are currently off limits to exploration and development Historic onshore producing areas will be called upon again to yield new discoveries from traps which eluded earlier exploration efforts. Tax incentives are needed to encourage the increasingly expensive and difficult exploration and development of those onshore areas to the inilable to the industry.

The second, extension of existing fields, has contributed substantially to new reserves. In Texas alone, 90 percent of the reserve additions in the last 15 years have come from existing rather than new fields. However, this performance will not be repeated if drilling activity does not improve. The Baker Hughes weekly rig count averaged 869 rigs in 1989, the lowest since record keeping began in the 1930's. The rig count is averaging approximately 1000 this year, barely above the very low average for 1986-88.

Drilling activity could also be hard hit by environmental legislation currently progressing through Congress. We believe, for example, that RCRA proposals alone could increase drilling costs by $50,000-$100,000 per well, That would substantially alter drilling economics since the average cost of all wells drilled in 1987 was $280,000. Also, meeting Clean Air requirements will require the expenditure of significant capita I and operating funds If our concerns are confirmed, then tax incentives will be needed to mitigate the crushing effect of these new burdens. Accordingly, Unocal supports proposals, such as an environmental expenditure tax credit, accelerated depreciation and current expensing of environmental capital outlays, in order to ease the burden of voluntary or required environmental costs. Tax-exempt financing for the costs of pollution control equipment, waste disposal facilities recycling facilities and other similar environmental costs would also help to ease the burden. Legislation allocating interest incurred in relation to environmental expenditures to U.S. income for purposes of Section 861 of the Internal Revenue Code would also help to eliminate the current penalty on environmental expenditures arising from the rules apportioning interest expense between domestic and foreign sources.

The third method is increased stripper well production. Unocal strongly supports tax incentives for stripper wells because, once marginal wells are shut-in, the oil left in the ground is lost forever. Under existing law only the independents qualify for stripper well tax incentives and the "transfer rule" prevents independents from taking percentage depletion on marginal properties purchased from majors The result is the premature abandonment of marginal wells. The rate of stripper well abandonments which had declined to a low of 6,614 wells in 1981, rose alarmingly to an average of over 18,000 wells in 1988. At a very minimum, the "transfer rule" should be repealed. Better yet legislation should be enacted to allow all petroleum companies to take percentage depletion on marginal production.

The fourth method is enhanced oil recovery (EOR). Today, most fields are abandoned after they have produced to a secondary economic limit. Successful secondary recovery, such as through the use of a waterflood, can recover about 40 percent of the original oil in place. However, heavy oil does not respond to secondary recovery and primary recoveries are low, typically only about 15 percent. Thus, over half of the oil we discover is being left in the ground! There are numerous methods within this area, usually involving the application of gas, chemicals or heat.

EOR has the potential to tap a substantial portion of that oil. For example, in heavy oil fields where we have instituted thermal projects, we are anticipating recoveries on the order of 40 percent. Unfortunately, EOR projects require a substantial long term commitment of funds which is extremely difficult to justify with today's volatile oil prices. Thermal projects (steam floods) cannot be temporarily shut down when oil prices fall. If a project is shut down and the steam in the reservoir condenses, permanent damage is caused to the reservoir. Thus, when prices are low, we are between the proverbial rock and a hard place. We have kept several money losing projects going because of our faith in the future, but that experience has tempered our appetite for new EOR projects.

Studies indicate that legislation to provide tax incentives for EOR would have a substantial impact on oil product ion with a minimal revenue impact. Senate bill 828, the "Enhanced Oil and Gas Recovery Tax Act of 1989," introduced by Senator Domenici, would increase reserves by about seven billion barrels according to a government analysis. That represents a whopping 25 percent increase in our nation's oil reserves. The estimated Federal revenue cost is only about $.50 per barrel and is less than the anticipated increase in state and local tax revenues Our energy security would be enhanced and the trade deficit would be reduced by about $125 billion. Such legislation would be in the national interest.

The fifth method of increasing domestic sources of energy is the increased development of alternative energy sources. Stable, long term tax incentives are needed to support such development. In addition, taxpayers in the alternative minimum tax position should not be precluded from currently benefiting from these incentives.

We support continued tax incentives for research and development in the areas of conventional energy production, alternate energy production and efficient energy use. However, we oppose tax incentives that would tilt the playing field in favor of a particular form of energy without creating a new source of energy. Alternate fuels should not be confused with alternate energy; alternate fuels may be desirable but converting one form of energy to another does not necessarily improve our energy security. For example, we would oppose any tax incentives to convert natural gas to methanol because that would be robbing Peter to pay Paul and because some of the energy would be lost in the conversion process.

There are definite indications that natural gas is the fuel of the future; it is relatively clean burning and it contributes less to global warming than other conventional fuels. While natural gas is relatively plentiful today, that could easily change as demand increases. Existing Section 29 tax incentives should be extended to further encourage the development of better technology to discover and develop nonconventional natural gas resources such as coal seam gas, Devonian shale, and gas in tight sands.

Geothermal, an alternative source of energy, is environmentally safe and is economically competitive at today's prices. The U.S. Geological Survey estimates that about 23 thousand megawatts of electrical power are recoverable from geothermal systems That equates to about 800,000 barrels per day of imported crude oil. We believe the existing energy tax credit for geothermal projects should be extended for at least five years in order to stimulate additional geothermal investment.

Unocal also urges prompt Federal action to support the continued development of oil shale technology. Unocal has had a sixty year commitment to developing shale oil as an alternative to conventional crude oil. Those of us involved in the shale oil project at Unocal are especially excited about the next three to five years. If given the opportunity to be developed, technological advancements may make shale oil an economically viable alternative in the future.

Our nation may require production from alternative energy resources, such as oil shale, sooner than anticipated. As the United States becomes more and more dependent on the world oil market, we risk facing price shocks and supply disruptions similar to, or even worse than, the 1970's.

Shale oil is one of the best alternatives, if not the best alternative, to crude oil. First, it is abundant. Most people are surprised to learn that our country has almost as much recoverable shale oil as all of OPEC has in recoverable crude oil. The Western United States has over 600 billion barrels of recoverable shale oil, most of it on federally owned lands, compared to just 25 billion barrels of domestic crude oil reserves.

Second, shale oil has been discovered to be a superior source of feedstock for transportation fuels and lubricants. Unocal's syncrude is co-processed with conventional crude oil by several refineries in the Midwest and Rocky Mountains. Most modern refineries can convert 100% of the syncrude into transportation fuels without the residue of heavy bottoms as with conventional crude oil.

And third, Unocal is closing in on defining the technological and economic parameters for the extraction of shale oil in commercial quantities as evidenced by its Parachute Creek Shale Oil Project.

Unocal's Parachute Creek Shale Oil Project in Colorado demonstrates Unocal's concentrated effort to develop oil shale. After four years and a cost of $650 million dollars Parachute Creek was completed and commenced operations in 1983. To date, Unocal has invested over $1.2 billion of its own dollars in its Parachute Creek Shale Oil Project.

Unfortunately, Parachute Creek has lost money every year since its inception. We no longer expect to recover any of our prior investment, and have entirely written the project off the company's books. Understandably, Parachute Creek has been unpopular with the investment community.

We made great strides last year in trying to reach that break even point by increasing production 40%, and reducing costs by 23%. Yet, we still lost $36 million dollars. Although $36 million dollars is a lot of money to lose, there is room for optimism. The project showed a significant improvement in 1989 over the $50 million loss in 1988, and the $103 million loss in 1987, and is expected to approach break even in 1990.

The Department of Defense is interested in oil shale as a secure, alternative source of domestic transportation fuels. Detailing that interest are two letters from The Office of the Assistant Secretary of Defense, one addressed to Colorado Congressman Hank Brown and the other to Richard Stegemeier. Copies of the letters are attached.

In the letter to Unocal, a briefing on Unocal's perspective of the future of the Parachute Creek Shale Oil Program was requested. Unocal met with representatives of the Department of Defense Energy Policy Council last year to discuss our progress at Parachute Creek. Subsequent to that meeting, the Council expressed its continued interest in conducting operational validation testing of shale-derived fuels by the U.S. Air Force.

Unocal cannot afford to continue investing millions of dollars on the shale project every year just to break even. The $85 million we anticipate spending on the project this year cannot be justified on a rate of return basis. Our lost opportunity costs could be partially offset by a modification to Section 29 of the Internal Revenue Code. Section 29 was enacted with the purpose of providing a tax incentive for production from oil shale and other non-conventional fuels

This Section 29 Credit provides a $3.00 per barrel tax credit for production from oil shale and other non-conventional fuel sources. Although shale oil is one of the most promising non-conventional fuel sources, our project has not benefited from this tax provision for three reasons: first, the credit is offset by any energy investment tax credit; second, the credit is reduced by the proportion of the production facility financed with tax-exempt pollution control bonds; and lastly, the credit is not immediately available to taxpayers subject to the tax code's alternative minimum tax.

Consequently, Unocal proposes a three-year moratorium on the application of these three restrictions and application of the credit to retort gases. Language to make these changes is attached. A three-year window of opportunity and the anticipated improvements in operating performance would enable Unocal to make additional technological progress. If Unocal can continue to operate the project, the technical, environmental and economic viability of oil shale technology can be greatly enhanced. This technology will be made available for commercial use on a non-exclusive basis pursuant to the terms of our agreement with the Department of Energy. If oil shale becomes a competitive energy source, it would limit the price of conventional Petroleum, increase domestic energy production, ease our dependency on foreign energy, and result in Federal royalty revenues from the government's current 80% ownership of the resource.

In conclusion, we support tax incentives to improve productivity and advance technology in ways that can make a meaningful difference in the long term. Tax incentives should be provided to encourage exploration and development of those few areas remaining for such activities. A variable import fee to establish a floor price for oil near the current market price would encourage increased production and increased conservation. Tax incentives for stripper wells and EOR would minimize the amount of oil left behind when existing fields are abandoned. In addition, we support tax incentives to encourage technological development in a variety of areas including non-conventional natural gas, geothermal and oil shale, which incentives taxpayers should be able to benefit from currently, even if they are in an alternative minimum tax position.

Thank you for the opportunity to present these views.

PROPOSED AMENDMENT to
The Internal Revenue Code
of 1986

(a) Section 29(b)(5) is deleted.

(b) Section 29(c) is amended as follows:

(1) By deleting the word "or" at the end of paragraph (1)(B)(i);

(2) By inserting the word "or" at the end of paragraph (1)(B)(ii); and

(3) By adding a new paragraph (1)(B)(iii) as follows:

(iii) shale.

(c) A new paragraph (10) is added to section 29(d) as follows:

(10) Special rule applicable to oil or gas produced from shale. --

The amount of credit allowed under subsection (a) shall not be reduced as set forth in paragraph (3)(A)(i)(II) of subsection (b); and shall not be reduced as set forth in paragraph (4) of subsection (b).

(d) Section 29(f) is amended as follows:

(1) By amending paragraph (1)(B) to read as follows;

(B) which (except for gas produced from shale) are sold after December 31, 1979 and before January 1, 2001.

and

(2) A new paragraph (3) is added as follows:

(3) Special rule applicable to gas from shale. -

The provisions of subsection (a)(2)(A), above, shall not apply to gas from shale.

(e) Paragraph (1)(B) of section 55(b) is amended to read as follows:

(B) the sum of the following:

(i) the alternative minimum tax foreign tax credit for the taxable year, and

(ii) the credit for producing fuel from a nonconventional source for the taxable year.

(f) The provisions of the Act shall apply to oil or gas produced from shale in taxable years beginning after December 31, 1989 and ending on or before December 31, 1992.

THE OFFICE OF THE ASSISTANT SECRETARY OF DEFENSE
WASHINGTON, DC 20301-8000

PRODUCTION AND LOGISTICS

(L/EP)

SEP 12 1989

Honorable Hank Brown
House of Representatives
Washington, DC 20515

Dear Congressman Brown:

Thank you for your recent letter to the Secretary of Defense concerning our continuing interests in shale derived fuels and the role that the UNOCAL Corporation's shale project in Colorado has served in that regard. The United States has vast oil shale resources which could provide a source of alternative fuel to meet this country's future energy needs. The Department of Defense is consequently interested in the development of this potential resource.

Pursuant to amendments to the Defense Production Act of 1950, UNOCAL Corporation, in 1981, was granted a guaranteed purchase price contract by the Department of Energy to develop technology to produce shale oil. Construction of a shale oil facility in Parachute Creek, Colorado, was completed in 1983. After spending approximately $1.2 billion of its own capital on the project, UNOCAL is still having difficulty lowering operational costs. It lost $102 million in 1987, $50 million in 1988, and may lose $25 million more this year. The plant, designed for 10,000 barrels per day of production, has finally been able to reach a sustained average daily production rate of 3,000 barrels. However, the plant has not been able to produce in economical quantities. The next three years appear to be very critical to finding a way to achieve economic production.

Recent discussions with UNOCAL officials indicate that, if they can continue to operate for three more years, they believe they can gain sufficient technical and operational experience to increase production to levels that would enable them to meet full scale operational costs. The decreasing rate of loss seems to support this contention.

The Department of Defense has begun a review of its prior plan for operational validation testing of military jet and diesel fuels refined from shale-derived synthetic crude. The program would use 3,000 barrels per day of military fuel derived from shale oil to operate aircraft and ground vehicles at one Air Force and one Army base in the western United States.

UNOCAL's shale project is the only potential source of shale oil feedstock for these military fuels. In view of the potential long-term energy security benefits of successfully demonstrating the suitability of synthetic crude for producing military products, it is in the interest of national defense to continue development of shale oil production technology.

Sincerely,

John A. Mittino
Deputy Assistant Secretary
(Logistics)

PRODUCTION AND LOGISTICS

(L/EP)

THE OFFICE OF THE ASSISTANT SECRETARY OF DEFENSE

WASHINGTON, D.C. 20301-8000

1 8 APR 1989

Mr. Richard J. Stegemeier
President and Chief Executive Officer
UNOCAL Corporation
P.O. Box 7600
Los Angeles, California 90051

Dear Mr. Stegemeier:

I would like to take this opportunity to open a dialogue with you regarding the possible acquisition and use of shale oil-derived, Military specification synthetic fuels refined from feedstock produced at UNOCAL's Parachute Creek Plant. In January, preliminary discussions I held with Tom Hairston and Peter Nichols indicated that UNOCAL would be able to project later this year when the Plant would be able to produce shale oil-derived transportation fuels.

We should discuss the possibility of DoD purchasing 2,500-5,000 barrels per day of 100 percent shale-derived jet and diesel fuels for use in an operational validation program at a designated Military location. Operational validation consists of operating a number of Military aircraft and ground vehicles exclusively on the synthetic fuel for a predetermined period of time, e.g., 18-36 months.

I recommend that a briefing on UNOCAL's perspective of the future of the Parachute Creek Shale Oil Program be the next step. My staff can arrange for the briefing to be presented in May at the Pentagon to the Department of Defense Energy Policy Council, which is composed of senior energy officials of the Office of the Secretary of Defense, Joint Staff, Military Services, and Defense Logistics Agency. Please advise me of your views on this matter.

Sincerely,

Jeffrey A. Jones
Director
Energy Policy

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PREPARED STATEMENT OF CHARLES J. MANKIN

Mr. Chairman and Members of the Subcommittee: A stable supply of energy, in terms of both quantity and price, is an essential requirement for the continued health of the Nation's economy and the well-being of its citizens. The most effective way to ensure the stability of that supply is to obtain a significant portion of the demand from domestic sources. Domestic sources still supply more than 80 percent of the total energy we consume, but we now import almost 50 percent of actual crude oil and refined product demand. In my judgment, the Nation is no longer in a position to avoid serious adverse effects to the economy and the well-being of the American people should a protracted disruption in imports occur.

The energy supply for the U.S. comes from five primary sources; petroleum (crude oil and natural gas liquids), natural gas, coal, hydro-electric power, and nuclear electric power. Petroleum provides almost one-half of the Nation's energy supply, natural gas and coal provide about one-quarter each, and electric power from hydro and nuclear sources combined provides less than 10 percent. That pattern of supply has been maintained with little change in magnitude for any of the commodities for the better part of two decades (Figure 1).

This energy is used in three sectors; residential and commercial, industrial, and transportation. In 1989, those three sectors consumed energy in approximately equal quantities (Figure 2). However, the composition of the primary energy supply required by each sector differs markedly. Natural gas and electricity provide more than 80 percent of the energy supply for the residential and commercial sector with refined petroleum products supplying most of the rest. Natural gas and petroleum supply about 75 percent of primary industrial energy demand with coal and electricity supplying most of the remainder. Petroleum supplies more than 97 percent of transportation demand with natural gas supplying most of the remainder.

The transportation sector depends almost entirely upon petroleum; all other uses of petroleum are essentially the by-products of the refining industry's efforts to supply the needs of this Nation's vehicles, planes, ships, and trains, and to keep the wheels of commerce rolling.

Regrettably, the petroleum industry is no longer able to meet the needs of this Nation solely from domestic sources. Production has declined severely, demand is on the rise, and as a result, imports of crude oil and refined products have risen dramatically in recent years and now amount to one-half of the total supply. This level of imports far exceeds the Nation's ability to ensure a secure supply of transportation fuel. One only needs to remember the long lines at service stations in 1973 when the U.S. was importing less than 35 percent of its needs to understand that a significant and protracted disruption of current supplies would have disastrous consequences for the economy of this Nation and the well-being of its citizens.

Imported crude oil and refined products come at a heavy price. That price is measured in both dollars and in adverse impacts on the environment from increasing tanker spills. (More imports means more tankers; more tankers means increased chances for tanker spills.) Increased offshore production is a far safer option for the environment.

The economic impact of petroleum imports is illustrated in Figure 3. Since 1970, the cumulative trade deficit has totaled about $1.3 trillion. For that same period, the cumulative value of crude oil and refined product imports is about $1 trillion. Thus, most of the merchandise trade deficit since 1970 can be attributed to those petroleum imports. As the quantity of petroleum imports continues to increase, so will the adverse economic and environmental effects.

Mr. Chairman, while most experts agree that U.S. demand for petroleum now exceeds the amount that could be obtained solely from domestic sources, the present level of dependence on foreign supply is both dangerously excessive and unnecessary.

Our task then is to identify the options available to the Congress and to the Administration that would assist in addressing this matter of growing concern. To identify those options, it is necessary to provide an overview of the domestic petroleum supply and related industry activity.

For more than 60 years, domestic petroleum production has been regulated by the major producing states. For the first 40 years of this regulation, the states estimated demand and pro-rated oil production among the producers to protect their correlative rights and to prevent physical waste of the resource. Prices remained stable, production increased, and the public enjoyed a stable supply of inexpensive transportation fuel (Figure 4).

In the early 1960s petroleum imports began to be a measurable component of the total supply. The lower prices for those imports imposed a restraint on domestic price increases which, along with a maturing resource base, led to a decline in domestic production. That, in turn led to a further escalation of imports. By the time of the crude oil embargo in 1973, imports had risen to about one-third of total supply.

The price escalations of the mid-70s stimulated an increase in domestic production of almost one million barrels per day over the period from 1977 through 1985. The popular opinion that no new oil was discovered and that existing reserves were merely depleted at a faster rate is wrong. In fact, more than 27 billion barrels of additions to reserves were developed during this 8 year period due to the higher prices (Figure 5). That amounts to more than 3 billion barrels per year. In addition, more than 137 trillion cubic feet of natural gas were added to reserves during the same period.

The fact that the domestic petroleum industry responded to economic incentives should come as no surprise, nor should the magnitude of the response. The addition of more than 27 billion barrels of crude oil and 137 trillion cubic feet of natural gas in an 8-year period should indicate that we are far from draining the last drops from our resource barrel. The Department of Energy's recently revised estimate of the 341 billion barrels of remaining oil resource in existing fields attests to this.

Mr. Chairman, clearly it will take economic incentives in some form if we are to maintain a domestic petroleum industry. The alternative is to become essentially totally dependent on foreign sources of supply to meet the transportation needs of our Nation.

Fortunately, it does not have to be this way. It is possible to maintain a viable domestic petroleum industry and still maintain some of the short-term economic benefits of foreign oil. To do so, three things must happen. These are:

1. Provide and assure long-term access for exploration and development to prospective Federal acreage in the Lower 48-States, Alaska, and the Outer Continental Shelf. These Federal lands contain most of the Nation's undiscovered oil and gas potential.
2. Establish an economic value or "floor-price" for imported crude oil. This would provide the domestic petroleum industry with a set of economic expectations in which investments in exploration and development could be made. Although such action would reduce some of the short-term economic benefits currently being enjoyed by the driving public, it would prove to be a very cheap insurance policy against long lines at the service station.
3. Significantly increase Federal support for a focused program in crude oil and natural gas recovery research. Estimates in the range of 300 billion barrels of remaining crude oil in existing fields is a target that is too large to continue to ignore. Regrettably, even with recent increases, the current level of Federal funding for such research is pathetically small. Recovery of only 10 percent of that estimated remaining in-place resource would more than double our present proved reserves, and would repay the Federal treasury several times over in tax revenue from the increased economic activity generated by that hydrocarbon recovery. In fact, recognized experts from government and industry suggest that with development of near-term and future advanced technologies, nearly 90 billion barrels of incremental reserves could be produced.

Let me conclude this presentation with a brief examination of the petroleum situation in Oklahoma to illustrate the need for Federal action of the sort previously described. Oklahoma has long been an important petroleum-producing state. Cumulative production of crude oil from 1907 (the year of statehood) to present exceeds 13 billion barrels. At present, Oklahoma ranks fifth in the Nation with a 1989 production of 118 million barrels (Figure 6).

Unfortunately, since the major price decline at year-end 1985, Oklahoma's annual production has dropped by 45 million barrels. At the present rate of decline, we will produce less than 100 million barrels of crude oil in 1991. The last time Oklahoma's annual production was that small was in 1919. If this trend continues beyond that time, Oklahoma will become a net importer of petroleum products by 1995.

The State still has potential to contribute importantly to the domestic production of petroleum. Opportunities for discovery of small fields remain good. However, it is difficult for the industry to think about small field exploration when they are in the process of abandoning existing wells at one of the highest rates in the State's history. Thus, the need exists to establish some sense of stability for the price of crude oil. Absent that, Oklahoma will continue to go out of the oil business.

Moreover, Oklahoma has substantial potential for recovering additional crude oil from existing fields. A recent study produced by the Interstate Oil Compact Commission estimates that Oklahoma has the potential to recover some portion of 6 billion in-place barrels of by-passed mobile oil from existing fields. In addition, the State also has the potential for recovery of some portion of 20 billion in-place barrels of residual oil from those same fields. To realize those opportunities, much work needs to be done to develop the needed understanding of the State's reservoirs and the processes that will be required to recover this additional crude. Through State-tax incentives as well as State-funded research, some progress is being made. However, since this issue is national in scope, the Federal Government must participate to a greater degree in cooperative funding of these needed investigations.

One step in the right direction to assist Oklahoma and the other producing states to realize their remaining petroleum potential is the incentives bill for EOR recently introduced by Senator Domenici. By limiting incentives to new EOR projects and to the point of payback, the bill limits the cost to the Federal treasury while providing the economic stimulus necessary to encourage the development of new projects. Furthermore, by providing an investment tax credit it will stimulate far more incremental EOR reserves than would have been realized from the bill as originally drafted.

Mr. Chairman, the time to act is now while the Nation still has a domestic petroleum industry that is capable of responding to our needs. The Department of Energy estimates that, at the present rate of well abandonments, between 60 and 70 percent of remaining U.S. reserves will be lost within this decade. If this view from the State of Oklahoma on the domestic petroleum industry has any merit, I believe it is much later than conventional wisdom would have you believe.

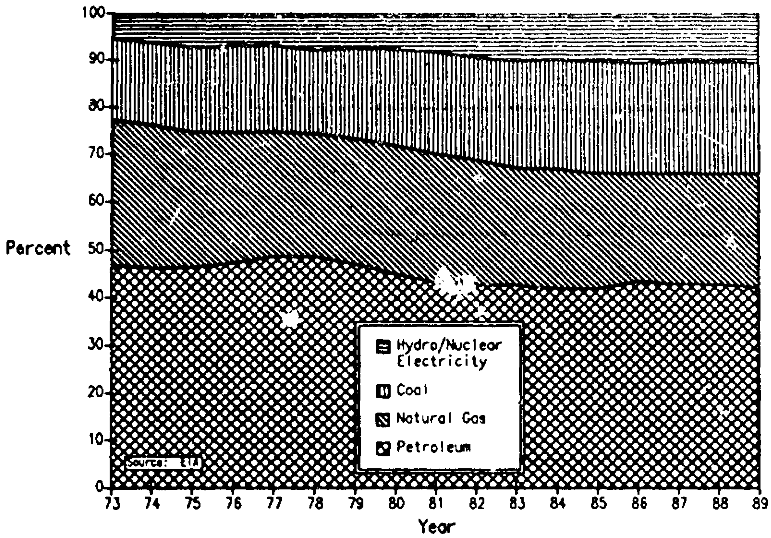

Figure 1. U.S. energy supply by percentage of each commodity.

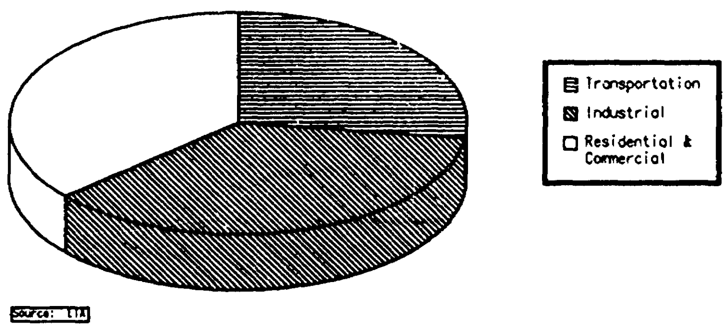

Figure 2. U.S. energy consumption by the three primary end-use sectors.

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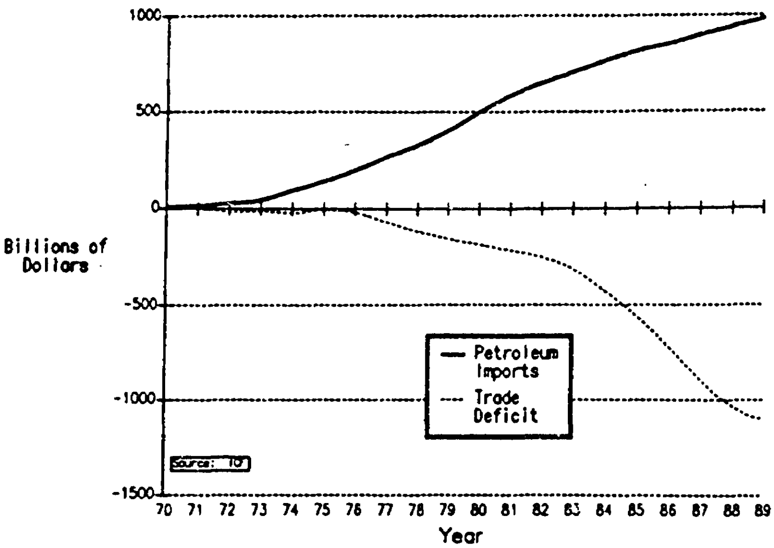


Figure 3. Cumulative petroleum imports versus the cumulative merchandise trade deficit in 1989 constant dollars.

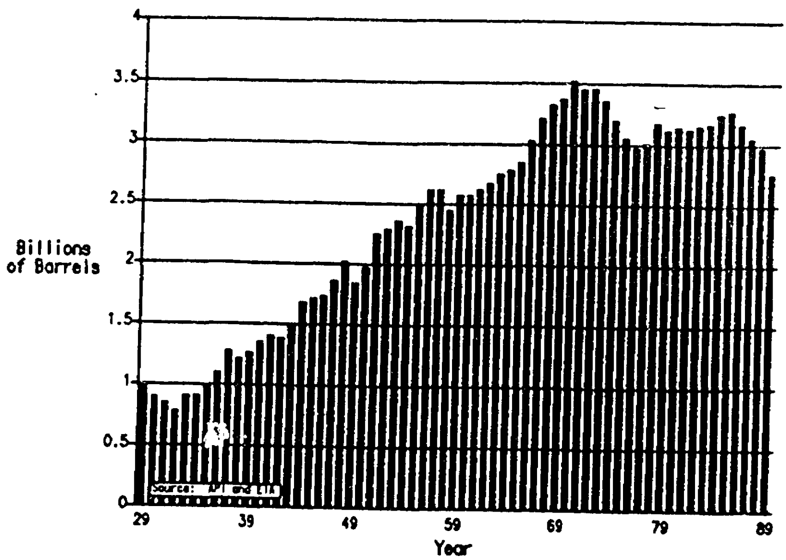


Figure 4. U.S. crude oil and natural gas liquids production from 1929 through 1989.

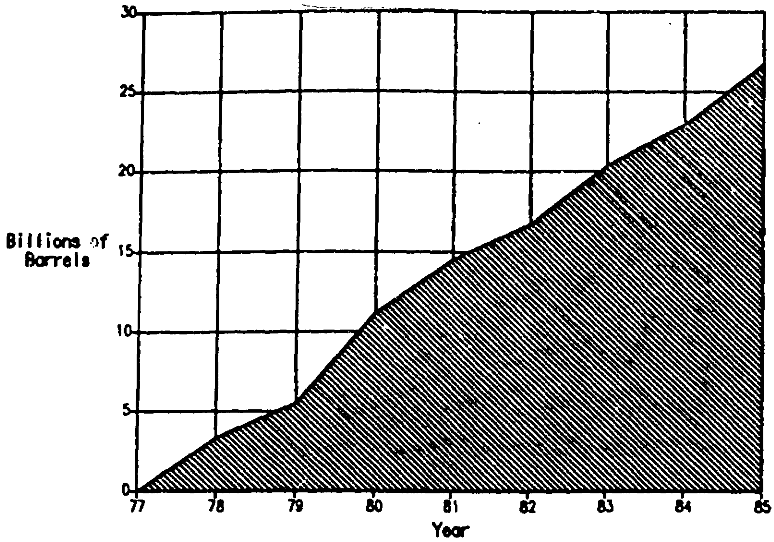


Figure 5. Cumulative net additions to U.S. petroleum reserves from 1977 through 1985.

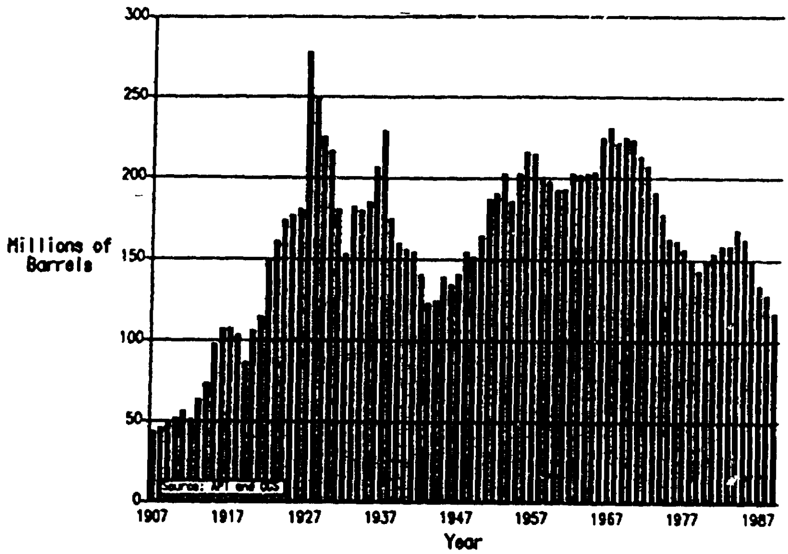


Figure 6. Oklahoma annual production of crude oil and natural gas liquids from 1907 through 1989.

PREPARED STATEMENT OF SANFORD MCCORMICK

INTRODUCTION

Mr. Chairman, I am Sanford McCormick, President of MetFuel, Inc., a Houston-based company involved in the development and production of coalbed methane. I am also appearing on behalf of the Section 29 Association, a coalition of companies in favor of extending the section 29 credit.

I have been active in the oil & gas business since 1956. In my 35 years in the business I have seen the U.S. go from a position of energy abundance where oil was prorated to 8 days a month in Texas and gas was flared as a worthless by-product to a condition of increasing dependence on foreign sources, with 1990 marking the first year in which imports have exceeded domestic production.

I believe we are headed for a serious problem in energy in the United States. Just as the inevitability of the savings and loan crisis should have been obvious four or five years ago, the fact than an energy crisis looms could hardly be clearer. Let's look at a few facts:

Oil—Domestic production peaked in 1970 at 9.6 million barrels per day, has declined 25 percent since then, and is currently declining at 7 percent per year. Between now and the year 2000, domestic oil production probably will fall to less than 3 million barrels per day. By the end of the 1990s, eighty percent of our nation's oil will be imported.

Gas—Since the 1973 peak production rate of 22.6 trillion cubic feet (TCF) per year was achieved, gas production declined 20 percent by 1988. Between now and the year 2000 gas production probably will decline to under 8 TCF/YR.

The difference between the savings and loan crisis we are currently experiencing and the energy crisis we will soon face is that the energy crisis will cost much more than the savings and loan crisis. Oil imports probably will cost $2 trillion during the 1990s, four times the total expenditure of the 1980s.

Mr. Chairman, it is absolutely imperative that the government look aggressively for ways to increase domestic energy production in a cost-effective manner. One of the most promising and cost-effective ways to do this is the constructive use of tax incentives. In my years in the business I have seen many incentives tried, and none have had anything close to the results achieved by the section 29 credit. In short, the section 29 credit works.

Section 29 of the Internal Revenue Code provides a tax credit for the production of certain nonconventional fuels, including natural gas produced from coalbeds, biomass, Devonian shale, geopressured brine, and, under certain circumstances, tight formations. The credit is also available for certain fuels produced from such alternative energy sources as oil shale, processed wood and coal. This credit expires for production from wells drilled or production facilities placed in service after this year.

It is indeed a pleasure to give my reasons for believing that this credit should be extended. I would like to say that it is extremely gratifying that the Senate Finance Committee is taking the time to make a serious effort to formulate the most intelligent and effective use of the tax code in an attempt to improve our very dangerous energy position.

BENEFITS OF AN EXTENSION OF THE SECTION 29 CREDIT

Over the past ten years, incentives provided by the section 29 credit have been very largely responsible for a dramatic increase in nonconventional fuel production. Of particular importance to my company, the credit has spurred coalbed methane exploration, development and production. This activity has been concentrated to date primarily in the San Juan basin of the Four Corners area and the Black Warrior basin of Alabama, where between 1 and 5 trillion cubic feet of proved reserves have been developed. Since the credit first came into effect in 1980, its impact is made clear by the fact that activity in the Black Warrior basin increased from a total of 154 coalbed methane wells drilled during the 1980-83 period, to over 1000 in 1989. It is reasonable to assume that virtually none of this development would have taken place without the incentive provided by the section 29 credit. If the "well drilled" date of the credit is not extended beyond December 31, 1990, the potential of these two basins will not be realized.

More importantly, there are dozens of other reservoirs of coalbed methane around the country that can be developed with the incentive of the credit. These are in Appalachia, in the Midwest, in the Rockies, and in other areas. I am attaching to this statement a map showing major U.S. reservoirs. If the "well drilled" date is extended, these basins will be aggressively explored. If it is not extended past the end of 1990 there will be little, if any, exploration and development activity in these other basins, at least until natural gas prices rise substantially.

The credit has also spurred the development of an industry to capture gas from landfills. The extension of the credit will further the development of gas from these sources as well as unlock the vast reserves of gas found in geopressured brine, Devonian shale, and tight sands. The credit also is instrumental in promoting the development of technology for extracting clean energy from coal.

In analyzing the results of the last few years, and contemplating an extension of the credit, a few benefits stand out:

1. Economic impact on the local community

With the credit, exploration and development efforts are expanding in many areas of the country. The economic impact of this expansion is widespread, extending beyond energy producers to businesses servicing the energy exploration and production industry.

A striking example of the economic impact of coalbed methane development is offered by the Black Warrior basin in Alabama. A detailed study prepared by the University of Alabama [1] concluded that among the many benefits of coalbed methane activity several were indeed impressive.

- Total expenditures in the two counties studied of approximately $4 billion over the 10-year period.
- The creation of a peak 12,900 jobs during the ten-year period.
- New state and local taxes of approximately $1 billion will be generated.

These results could be duplicated in the 1990s in coalbed methane, Devonian shale, and tight sands basins around the country. It makes a lot more sense to promote that development than to send increasing billions of dollars abroad for imported oil.

2. Effect on the cost of oil imports and the balance of payments

The increased production of natural gas and other nonconventional source fuels can reduce the trade deficit and put downward pressure on the price of oil. The effect of discovering new domestic energy reserves is made apparent by analyzing the impact of the discovery of 1 TCF of gas, a small fraction of the potential of coalbed methane. One TCF is roughly the equivalent of 160 million barrels of oil that do not have to be imported. This added 1 TCF of gas reserves has a double-barreled effect.

- The trade deficit will be reduced by at least $3.2 billion through reduction in the cost of oil imports, assuming a cost of $20 per barrel. In fact, there is ample reason to believe that the cost of imports over the next twenty years will average substantially higher than $20 per barrel, possibly bringing the ultimate cost to the $4–5 billion range. Since coalbed methane, Devonian shale and tight sands have the potential of developing many trillion feet of gas reserves, the savings in oil import costs could be very impressive. The development of significant domestic gas reserves has a strong depressing effect on worldwide oil prices, thus further reducing the cost of imports. The dramatic price increases ($5–6 per barrel) that resulted from relatively small supply disruptions caused by the Valdez spill and the North Sea platform shutdowns, as well as the run-up in prices following last December's cold snap, are but some examples of how much world oil prices are affected by small changes in supply-demand balances.

3. Environmentally preferable

The extension of the credit will also further Congress' environmental goals. Increased reliance on clean-burning natural gas will reduce the risk of global climate change, lessen the amount of acid rain, and reduce ground-level ozone and carbon monoxide. For example, methane seepage from coal seams, thought to be a factor in global climate change, is reduced by drilling in coalbeds.

COST OF THE CREDIT

Compared to the many benefits listed above, the only negative to an extension of the credit is some loss of potential tax revenue, but in this regard it is critical to bear in mind three considerations:

[1] "The Economic Impact of Coalbed Methane Development on Jefferson Tuscaloosa Counties" by the School of Mines and Energy Development and The Center of Business and Economic Research. The University of Alabama. March 1989.

1. The potential tax loss applies only to revenues from gas sales that would have not been generated in the first place, if it were not for the incentive provided by the credit.

2. The revenue loss is only relative to the gas discovered and produced; there is no revenue loss if no gas is produced, and as pointed out above, the benefits greatly exceed this one negative.

3. Any theoretical revenue loss will be spread out over the entire period of the credit (1990-2000) and will not impact one budget year.

Because of these considerations and the results achieved to date, our opinion is that this type of credit has proven itself to be an effective incentive to develop new energy reserves at a very reasonable cost. We believe that it would be far more cost-effective than a small tax credit on drilling expenditures.

METFUEL, INC. AS A CASE HISTORY

The example of MetFuel, Inc., the Company of which I am a founder and President, is a rather classic and powerful example of the impact of the section 29 credit on the oil and gas industry. A few facts tell the story.

- The Company was founded in November of 1988 to develop coalbed methane, initially in the Black Warrior Basin of Alabama, where to date all of its activities have been concentrated. The property acquired was largely unproven or "wildcat" in nature and the economics would not have justified acquisition and development without the section 29 credit.
- Without the benefit of the credit, the internal rate of return was less than 10% and payout in excess of five years. In short, without the existence of the credit, MetFuel would not have been founded, and the property would not have been acquired and developed.
- Because the section 29 credit made the economics of the prospect sufficiently attractive, MetFuel acquired 70,000 acres and attracted capital for development of the property. From November of 1988 through the end of this year, MetFuel will have drilled 500 wells and developed reserves in the proved, possible, or probable category of several hundred billion cubic feet.
- MetFuel is a company with approximately 80 full-time employees, and also employs a large number of consultants, as well as drilling contractors and service company people, etc. Full development of the property will entail the expenditure of approximately $250 million and will create a large number of jobs, as well as generate significant new tax revenues for the local community. We are also helping to revitalize the oil and gas community in my hometown of Houston. MetFuel's activity could result in the addition to U.S. gas reserves of more than 1 Trillion cubic feet, with the resulting $4-5 billion reduction in the balance of payment deficit discussed above.

None of this would have happened without the section 29 credit.

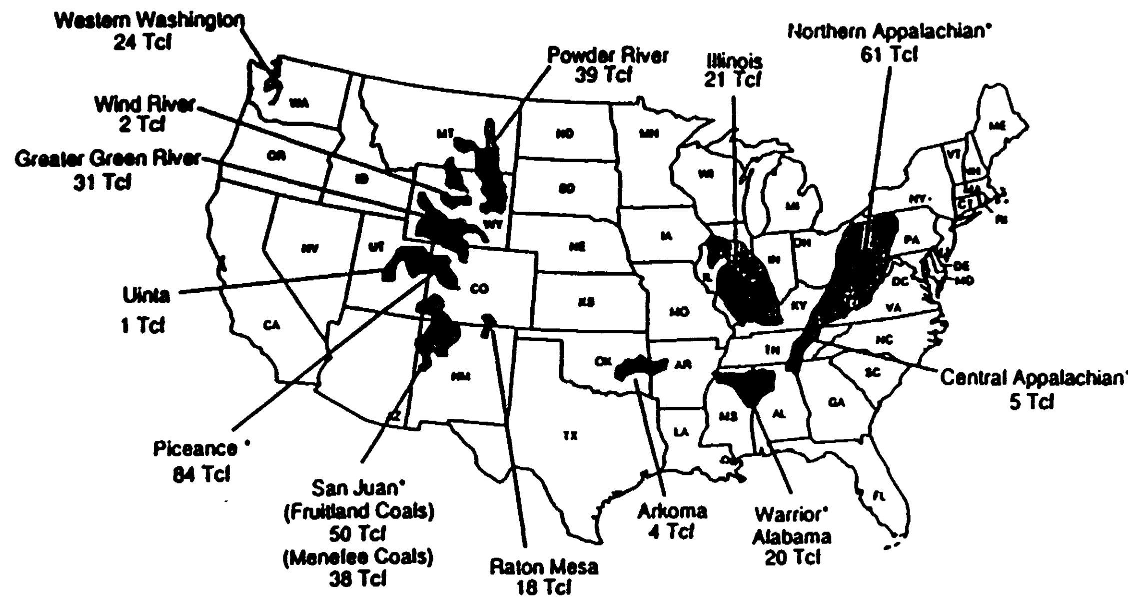
It is also instructive that our company recently acquired coalbed methane holdings in the Hanna Basin in the Rockies. The Hanna Basin does not even appear on the popular maps showing coalbed methane locations; it represents one of many reservoirs that will be developed in the 1990s if the section 29 credit is extended. One thing is clear: if the credit is not extended, the likelihood that we will be able to drill wells on new holdings will be slim.

MetFuel is in no way unique, but merely a classic example of what the American entrepreneurial spirit can and does achieve, given the proper economic incentive. If the credit is extended, there is every reason to believe there will be more "MetFuel Stories" in the industries pursuing the production of coalbed methane, landfill methane, gas from Devonian shale, tight sands and geopressured brine, and other nonconventional fuels. And each of these will have a positive impact on the nation's energy security, balance of payments and general level of economic activity.

In conclusion, the benefits of the section 29 credit far outweigh the one perceived negative, the possible loss in tax revenue. An extension of the credit should have a very high priority in this committee's drafting of tax legislation.

The 14 members of the Section 29 Association urge this Committee to extend the credit.

Coalbed Methane Resources of the U.S.



*Detailed Geologic Appraisals Completed by GRI/ICF-Lewin

Total Resource ≅ 400 Tcf

ICF Resources Incorporated

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PREPARED STATEMENT OF MARK G. PAPA

DISCUSSION

United States natural gas supply and demand appear to be on a collision course. During the mid and late 1980's domestic natural gas supply comfortably exceeded demand, providing the market mechanism for the current low natural gas prices. However, domestic natural gas demand has grown roughly 5% per year since 1986. Concurrently, low gas prices have depressed natural gas drilling activity for new reserves. In 1989, 9,500 gas wells were completed as compared to 19,000 completions in 1982. Attachment 1 shows that domestic gas reserves have declined steadily since 1973. This, in turn, has reduced natural gas deliverability such that most forecasters expect a significant tightening in the natural gas supply-demand balance during the next few years. The cumulative effect of decreased drilling activity on natural gas supply is shown on Attachment 2. This graph shows that 40% of our current gas production comes from wells completed subsequent to 1985. Since such a high proportion of the nation's, supply comes from recent vintage wells, continuation of the current low drilling levels will exacerbate the nation's gas supply problems.

Natural gas found in low permeability (tight) formations is an increasingly important component of our nation's energy resource portfolio. As reserves from conventional sources are consumed, other alternatives for reserve replenishment must be found. Tight gas formations offer the largest proven resource base available to provide this replenishment. Attachment 3 shows that tight gas formations are widely distributed. Tight gas is found in 21 states, and is currently produced in 16 states as diverse as Texas, New York, Oklahoma, Alabama, and Ohio. A 1988 DOE study indicated that tight gas reserves comprise approximately 180 trillion cubic feet or one fifth of estimated reserves in the lower 48 states. The National Petroleum Council is more optimistic and estimates there are 500 trillion cubic feet of untapped potential tight formation reserves in the contiguous U.S.

Tight gas is more difficult to develop than conventional gas because the rock formations are less permeable, and therefore there is a lower ability for gas to flow out of the formation. To generate a meaningful production rate, tight gas wells must be fracture treated, an expensive procedure to artificially increase the formation permeability. In many instances, the costs to fracture treat a tight well equals the cost to drill. Therefore, tight gas is more costly to develop than conventional gas.

We believe that the Section 29 tax credit incentive, if properly focused, is the best vehicle to stimulate domestic natural gas production and reserves. Unlike an across the board credit for all domestic drilling, the Section 29 credit is useful only if a well is successful. If the well is unsuccessful, all of the risk of drilling stays with the producer and no credit is available. Additionally, the Section 29 credit will focus industry activity on a proved large resource base. There is no question that these tight gas reserve exist. Similarly, the effectiveness of the Section 29 credit has been recently proven. Coal seam gas is currently eligible for the credit, and recent results from the San Juan Basin in New Mexico and Colorado shows that the tax incentive has stimulated a coal seam gas drilling boom in this area, with positive national energy results. We estimate that 1,200 coal gas wells will be drilled in this basin by year-end 1990, generating 3.6 trillion cubic feet of reserves with a peak deliverability of 720 million cubic feet per day. Depletion of these reserves will take over 50 years. Most of this drilling is a result of the Section 29 tax incentive. In the past, this tax credit has also stimulated tight gas drilling. The top chart in Attachment 4 shows yearly drilling activity in East Texas, which contains both conventional and tight gas formations. During 1970–77, drilling in conventional formations exceeded drilling in the tight Cotton Valley sand. By 1982, when tight sand incentive pricing was in place, the number of tight gas completions actually exceeded conventional completions. Subsequently, with the advent of decontrol, the ratio of tight to conventional completions returned to more normal patterns as these incentives disappeared. The 1989 flurry of Cotton Valley tight gas activity is related to the Section 29 credit which terminated on May 12, 1990 for certain vintages of tight gas. The bottom graph in Attachment 4 shows that tight gas is an expanding source of supply. U.S. tight gas production increased from 40 billion cubic feet (BCF) in 1979 to the current 1200 billion cubic feet (BCF) level.

The above data indicates that Section 29 incentives are effective—this is why Enron Oil & Gas supports the Section 29 legislation proposed by Congressman Andrews (H.R. 5351) and Senator Domenici (S. 2288).

Restoration of the Section 29 Tax Credit for Tight Gas Formations would provide the following benefits:

1. Additional supplies will help keep energy imports and natural gas consumer prices down

The steady increase of oil imports is of serious concern from the country's balance of payments standpoint. Additionally, this high degree of imports affects our nation's ability to control our own energy destiny. With oil imports now exceeding 50% of U.S. consumption and growing, any sharp price hike such as experienced in the late 1970's and early 1980's would have a large negative impact on the trade balance. Additional domestic gas supplies can be expected to displace demand for imported oil. Creation of a national natural gas market and the strong supply/demand relationship has kept natural gas prices low during the latter half of the 1980's. Additional gas supplies will tend to keep future consumer prices down. The cost of providing the tax credits is not large when viewed against these factors. In fact, if gas prices were kept lower by only 1¢/MCF, that would amount to about $180MM savings per year for consumers, which is more than the program would cost.

2. Environmental benefits from natural gas

Increased natural gas supplies will allow additional use of natural gas in providing a better environment. Long life tight gas sand wells are a good source of supply for new electrical generating capacity. Increasing natural gas supplies should have a high priority in providing help to the environmental effort.

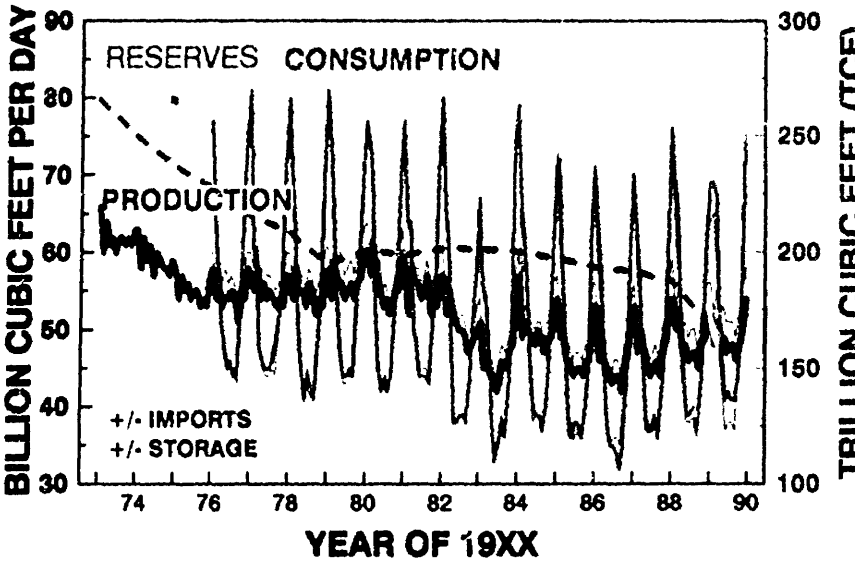
3. Maintenance of the infrastructure in the domestic industry and further development of new technology

Incentives to provide additional wells drilled in tight formations will help promote new and better technology in drilling and completions. New hydraulic fracturing technology has improved the tight sand results and further gains can be expected. However, with the high costs of operating in tight sand areas, little drilling is being undertaken today. In some areas where Enron Oil & Gas operates, wells can cost $300,000 to $500,000 to drill and completion and fracturing costs can run almost the same amount. A tax credit of 52¢/MCF will provide a significant incentive to get more wells drilled.

Enron Oil & Gas Company is a large independent domestic exploration and production company. Approximately 91% of our natural gas reserves are located in the U.S. Enron Oil & Gas is basically spending its available cash flow to develop new natural gas supplies. The company has been successful in developing new domestic reserves and domestic gas production volumes in the first half of 1990 are 34% higher than the equivalent 1989 period. Enron Oil & Gas is active in several tight sand areas in Texas, Utah, and Wyoming. If tax credit incentives for developing tight sands were reinstated, any cash flow generated from the tax credits would be spent on drilling tight sand wells. With a properly focused tax credit, Enron Oil & Gas estimates we would drill up to 500 additional wells within five years. The economic benefits of a 52¢ tax credit would provide a strong incentive to commence such a program. Providing incentives based on actual production levels appears to be the most effective, lowest cost way for this nation to reduce its dependence on foreign oil while meeting environmental goals.

Attachment 1

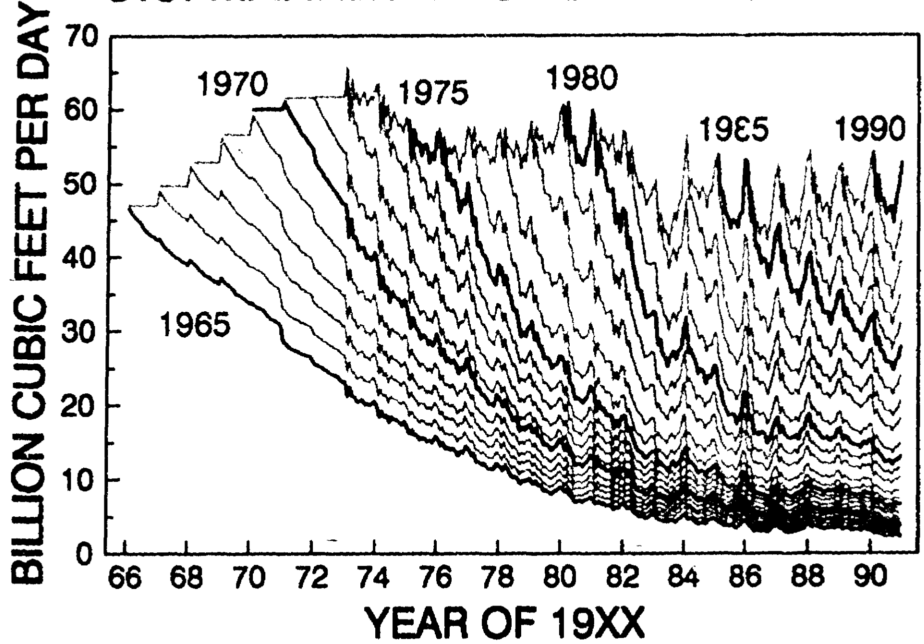
The Gas Gap



- **Gas Oversupply Basically Gone**
- **Gas Reserves Still Dropping**
  - **266 Tcf as of January 1, 1973**
  - **168 Tcf as of January 1, 1989**
- **To Meet Steady or Expanding Market Must Provide New Supply Sources**

Attachment 2
Declining Additions

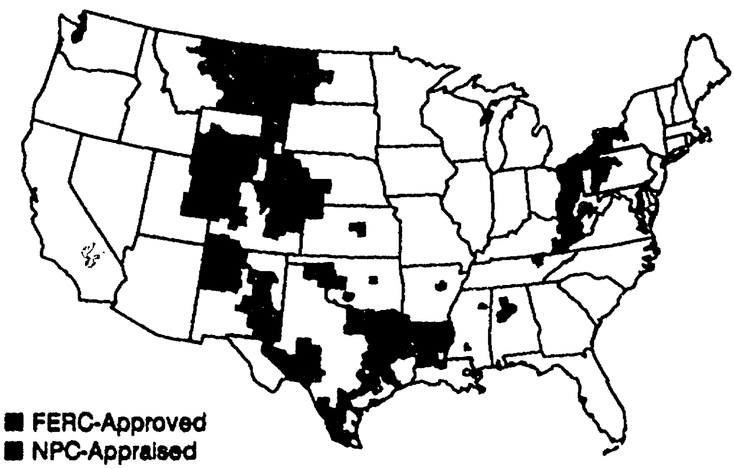
U.S. MARKETED GAS PRODUCTION



- **Rapidly Declining Deliverability**
- **High Dependence on New Drilling**
- **40% of Production from Wells Drilled after 1985**

Attachment 3

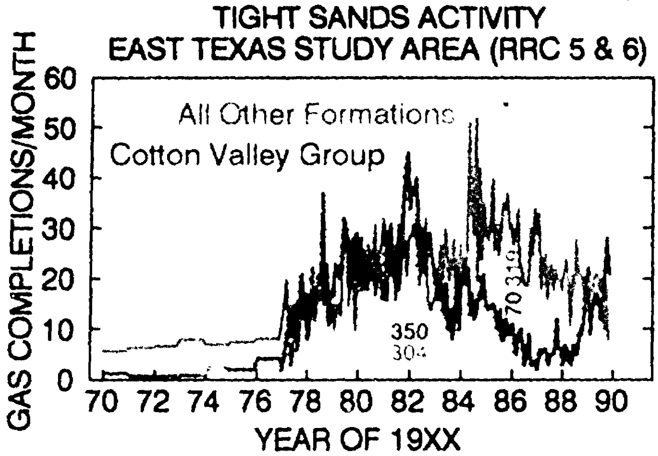
Tight Gas Formations - Widely Distributed Resource With Significant Reserves



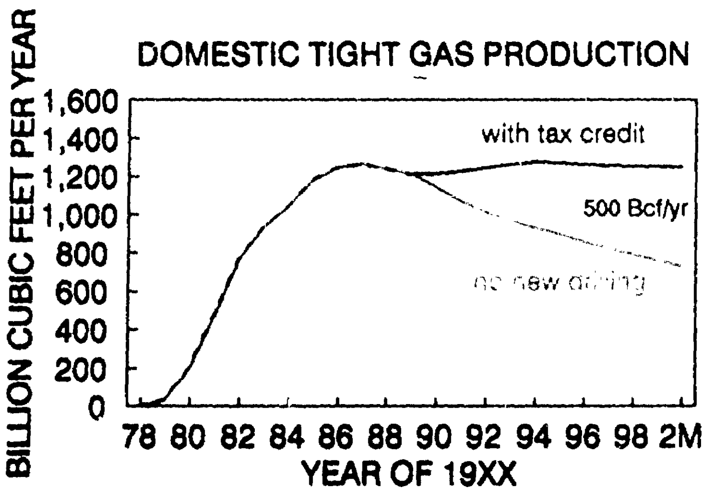
Source: EIA & NPC

- **Tight Gas in Twenty-one States**
- **Production from Sixteen States**
- **Additional FERC-Approved Areas**
- **Additional NPC-Appraised Areas**
- **Potential > 500 Trillion Cubic Feet**

Attachment 4
Section 29 Tax Credit - An Effective Incentive



- **Cotton Valley Study**



- **Nationwide Study**

PREPARED STATEMENT OF JAMES L. PAYNE

Mr. Chairman and Members of the Committee: I wish to thank you for this opportunity to speak to you today concerning the growing U.S. dependence on foreign oil and gas imports. I am the President and Chairman of the Board of Santa Fe Energy Resources, Inc., but I am speaking to you today on behalf of the Domestic Petroleum Council which is a national trade association representing large independent oil and gas companies actively engaged in oil and natural gas exploration and production in all of the major basins in the United States. Its members represent approximately 35 percent of the U.S. oil and gas reserves held by independent producers.

STATE OF THE DOMESTIC OIL AND GAS INDUSTRY

Domestic crude oil production declined below 7.6 MM B/D in 1989, the lowest level in 25 years, from more than 8.9 B/D in 1985 representing a 15 percent decline.[1] Even more alarming, the decline rate is accelerating with 1989 crude oil production falling 6.2 percent below 1988, representing 509,000 fewer barrels produced per day, a record annual decline.[2] At the same time, domestic petroleum demand has risen from 15.7 MM B/D in 1985 to 17.2 MM B/D in 1989, a 10 percent increase.[3] These two trends have caused a high growth rate in crude oil and petroleum products imports. In 1989 net imports totaled over 7.1 MM B/D, approaching the peak levels of 1977–79, up from 4.3 MM B/D in 1985.[4] Imports represented 41 percent of domestic oil consumption in 1989 and contributed $49 billion to the U.S. trade deficit.

Natural gas production has not kept pace as consumption has risen 10 percent from 17.3 Tcf to 18.95 Tcf.[5] It is generally expected that gas reserves and production are likely to decline in the next several years. As a fuel that burns more cleanly than coal or oil, gas is seen by many as the fuel of the future. The pending Clean Air Act amendments would increase demand for gas, and many predict high demand growth due to environmental regulation.

Exploratory wells drilled for oil and gas have declined from 12,208 in 1985 to 5,249 in 1989.[6] Total U.S. footage drilled has fallen 59 percent from 316.8 MM feet in 1985 to 130.7 MM feet in 1989.[7] Active drilling rigs have declined about 60 percent since 1985.

TAX DISINCENTIVES

As a capital intensive industry which must operate in an environment of volatile prices, low margins and higher risk domestic exploration and development opportunities, the oil and gas industry is especially vulnerable to tax disincentives like the following:

INTANGIBLE DRILLING COSTS (IDC)

Intangible drilling costs are critical to oil and gas exploration and development. However, the alternative minimum tax (AMT) imposes a double penalty on IDC. First, IDC expense, less IDC allowed under 10 year amortization, is added back into the AMT tax base to the extent it exceeds 65 percent of the taxpayer's net income from oil and gas. Then, 75 percent of the excess of IDC expense over IDC allowed under 5 year amortization is again added to the AMT base. The first penalty is called a preference and has the effect of penalizing drilling when prices decline. The second penalty, the ACE adjustment, effectively increases the tax burden on drilling by a factor as much as 5 times as compared to the regular tax.

TANGIBLE COST RECOVERY

Cost recovery for tangible personal property used in oil and gas exploration, development and production is drastically slowed under the AMT. Therefore, low oil prices can have the effect of slowing down cost recovery significantly. Interest and overhead capitalization may be required for oil and gas leases despite the risks and

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[1] *Monthly Energy Review,* (Department of Energy/Energy Information Administration), (December 1989), Table 3.1a, p. 46.
[2] *Ibid.*
[3] *Ibid.*
[4] *Ibid.,* Table 3.1b, p. 47.
[5] *Ibid.,* Table 4.2, p. 67.
[6] *Quarterly Completion Report,* (American Petroleum Institute), (Fourth Quarter, 1989), p. 4, and prior reports.
[7] *Ibid.*

uncertainties of exploration and development. Geological and geophysical costs (G&G) must be capitalized. Oil and gas exploration is excluded from the R&D credit. Capital loss limits hit oil and gas harder due to IDC and depletion recapture requirements.

OTHER DISINCENTIVES

Industry practices, such as forming joint ventures (needed on account of high risks and high capital costs), are impeded by various restrictions. For example, the IRS has published new regulations under which tax deferral on like-kind exchanges may be denied to partnerships whether or not they elect out. Rev. Rul. 77-176 taxes certain farmout transactions. IDC must be capitalized in certain carried interest arrangements.

In recounting some of the disincentives to oil and gas activity, the Windfall Profit Tax (now repealed) must be recalled as the largest. The industry was called upon to pay back as much as 70 percent of its net income from oil and gas property under that tax. Now the industry faces heavier tax penalties under the AMT despite low prices. This is a case of "heads you lose, tails you lose."

NEED FOR POSITIVE INCENTIVES

Significant tax incentives will be needed as part of a National Energy Strategy to increase domestic oil and gas production. A broad based oil and gas incentive applicable to all domestic reserves and all oil and gas producers is the only means of effectively and efficiently stimulating a significant response in overall domestic supplies on a national scale. Such an incentive should directly stimulate those activities which must occur in order to obtain increased domestic oil and gas production. By definition, such activities are the search for and development of new oil and gas reserves in the U.S.

EXPLORATION AND DEVELOPMENT INCENTIVE

I now turn to our credit proposal which; in large measure, is based upon earlier proposals, such as the bills sponsored or supported by yourself, Senator Bentsen, Senator Domenici, Congressmen Archer, Andrews and others. The new elements in our plan are a refinement and direct development of the fine work which preceded our proposal. We thank you, Mr. Chairman, and your colleagues for your leadership.

Exploration and development (E&D), by far the largest controllable area of the industry's budget, have been cut the most in this low price environment. Therefore, earned E&D credits would be plowed back into new exploration and development projects at a high reinvestment rate. Since fixed costs and overhead are already covered by operating budgets, such new spending would add new oil and gas reserves at a lower incremental cost than average historical costs.

In light of the long lead times from commencing exploration to commercial production, there is a need to stimulate both exploration and development. However, exploration, entailing higher risks, should earn credits at a higher rate than would be accorded development. Standard industry definitions can be used to distinguish exploration from development activity.

A 15 percent exploration credit would apply to the following qualified expenditures, whether or not capitalized:

- Geological and Geophysical Costs (G&G)
- Intangible Drilling Costs (IDC)
- Tangible property costs used or installed in exploration activity

The following expenditures would qualify for a 5 percent development credit, whether or not capitalized:

- Intangible Drilling Costs (IDC)
- Tangible property costs used or installed in developing an oil or gas reservoir

This proposal is designed with a base period adjustment to provide the greatest incentive at the margin for increased E&D activity while reducing the overall cost of the credit. Under the base period adjustment a one-third reduction would apply to current qualified E&D expenditure at or below the average base period level. The one-third figure represents the approximate maximum regular tax benefit of E&D expenditures.

However, current expenditure above average base period levels would not suffer the one-third reduction. Therefore, a higher incentive would apply to exploration and development expenditures beyond base period levels. As a result, the credit would be especially effective in increasing exploration and development activity.

Average base period expenditure would be computed separately for exploration and development based upon the 5-year period of 1986 through 1990, the low price environment which still prevails today. All future credit years would measure increased expenditures in exploration and development by reference to these same base period levels.

The credit would be permanent in order to provide an effective incentive. An early phaseout given volatile prices would defeat the incentive effect. The credit would offset both regular tax and AMT. A credit carryforward of 15 years is proposed with no carryback.

An important complement to this incentive proposal would be the elimination of the AMT preference for IDC and the provision of an offset of 100 percent of net income from oil and gas against the ACE adjustment for IDC. This would greatly diminish the counterproductive AMT penalty on IDC but still limit IDC expenses to oil and gas producers for AMT purposes.

This credit would be effective in stimulating new oil and gas reserves and production in the U.S. It would significantly reduce foreign imports, increase GNP, reduce trade deficits, provide new jobs, strengthen the industry's infrastructure and enhance the nation's energy competitiveness and national security.

This credit would work efficiently and would have a reasonable cost. We estimate that 1.77 billion equivalent barrels of new reserves would be added at a cost to the government over 5 years of about $2.50 a barrel after considering the effects of increased production on government tax collections and royalty take.

Mr. Chairman, we ask that you seek a formal revenue estimate from the Joint Committee on Taxation for our proposal. We have attached a summary description of our tax credit proposal for this purpose.

In conclusion, eliminating or mitigating Tax Code disincentives to oil and gas investments is a worthy objective. We earnestly hope that progress can be made to mitigate or eliminate them. However, at this point, the nation and the industry need an effective and significant tax incentive to increase domestic oil and gas supply. We urge you to consider our proposal today as a critical part of a comprehensive National Energy Strategy designed to address that need.

Prepared Statement of James E. Russell

Mr. Chairman and Members of the Committee: My name is James E. Russell, and I am an independent oil producer located in Abilene, Texas. I appear here today as President of the Texas Independent Producers and Royalty Owner Association (TIPRO), which has approximately 3,000 members with an oil or gas interest in Texas and is the nation's largest state-level organization representing the independent sector of the oil and gas producing industry. With me is Stacey Smyre, Chairman of TIPRO's National Energy Policy Committee, who will be available to help respond to your questions.

In the fall of 1989, (TIPRO) participated in Department of Energy hearings designed to initiate a national energy strategy. TIPRO pressed its case for preservation of a defined core supply of domestic energy as the basis for a viable national energy policy that would serve to keep imported energy flow at levels consistent with national energy objectives. (See Appendix A)

TIPRO realizes that a feasible definition of core supply must be a moving target that is periodically revisited so as to be reflective of changing events. It also must extend beyond crude oil and natural gas to encompass all forms of domestic energy—along with conservation practices—that serve to displace import flow. The Association also realizes that a core supply objective must be an ideal goal to achieve and maintain rather than a concrete requirement mandated by government edict.

Nevertheless, the Association strongly believes there are many ways in which Congress and the Administration can encourage or enable the domestic energy industry to respond to the task of achieving an agreed urn goal. Of course, TIPRO speaks only to the petroleum portion of this program and leaves discussion of other fuels and their role to others.

Before doing that, however, a brief look at the generally anticipated energy picture for the remainder of the century serves to place petroleum's role in better perspective. First, the nation's increasing concern with environmental initiatives and their effect on energy usage may well renew conservation habits of American consumers experienced during the period of 1975-85. Should this occur, total energy demand may again stabilize as it did then with conservation practices balancing out increase in energy use stemming from population increase and expansion of the nation's economy.

Stabilization may also be the by-word during the same time frame for energy supply from nuclear, coal and renewable sources. No more new nuclear plants are anticipated before the year 2000 as the public continues to struggle with safety concerns, such as the Hanford plant situation recently revealed in the northwest. Significant increase in coal production may well have to wait for expensive scrubber installation as clean air objectives move to center stage with amendments to the Clean Air Act. As for renewable sources, energy economics seen' to rule out aggressive expansion of supply for the foreseeable future.

If, in truth, the nation is moving into a period of stabilized energy demand and energy supply contribution from non-petroleum sources, then it would appear that domestic crude oil production, domestic natural gas production and petroleum imports (including crude oil, oil products, compressed natural gas, natural gas liquids and natural gas) will be competing for a basically well defined and stabilized portion of the U.S. energy market.

DEFICIENCIES IN CURRENT NATIONAL ENERGY POLICY

Currently, petroleum's overall portion amounts to the equivalent of some 25 million barrels per day, or approximately two-thirds of the nation's energy market. (See Appendix B Chart) An effective national energy policy should pose the question: to best serve the nation's economic, environmental and security interests, what portion of that 25 million barrels daily should be filled by domestic oil, domestic gas, and imported petroleum during the decade ahead? Once that guideline is struck, subject, of course, to periodic revision, the next question arises, what changes in governmental programs and taxing patterns can be initialed to encourage the appropriate supply pattern from these three basic sources?

Under current national policy, supply contribution has shifted from domestic oil and gas to imports annually since 1985 by an average of some 800,1300 barrels per day. (See Appendix C Chart) This shift has led to several undesirable consequences. It has added more than $20 billion to the nation's annual petroleum import bill, which now approximates $50 billion. It has increased tanker flow of oil into U.S. waters by more than 40 percent, thereby raising the risk of oil spills in U.S. Coastal waters by a similar margin. The move to imports has dramatically increased U.S. reliance on relatively insecure Mid-East oil, since virtually all new import flow must come from Persian Gulf source countries that hold most of the world's reserve productive capacity.

Other undesirable results include increase in governmental costs to expand and maintain the strategic petroleum reserve and protect the tanker sea lanes used to transport the larger import volumes. In addition, of course, there is the damage that occurs to the domestic oil producing industry and the nation's economy, as the infrastructure and job opportunity in the industry is decreased or moved abroad by the shift to imports from domestic production.

Obviously, it would be desirable policy to reverse this shift and begin to displace imports with domestic oil and gas production, or at least end the shift to imports by establishing domestic supply stability. However, two questions must be dealt with before corrective action can be taken. First, are there sufficient domestic oil and natural gas reserves available for the productive capacity needed to reverse or halt the shift? If so, are there feasible mechanisms and incentives available to the nation that make it worthwhile to generate the industrial capability needed to reverse or halt the shift—particularly in view of the adverse circumstances now being experienced under current policy that allows the shift to occur?

TIPRO firmly believes the answer to both questions is yes.

FUTURE DOMESTIC PETROLEUM SUPPLY AVAILABILITY

In February of this year, the Industry Capability and Goals Committee of the Texas' Governor's Energy Council reported findings applying to the next 50 years. The group, chaired by Edwin Cox of Dallas, contended that the domestic oil industry and the nation's reserve holdings are fully capable of sustaining current production levels of 7.9 million barrels daily for crude oil, condensate and natural gas liquids. This effort would require restoration of price to $25 per barrel (in 1986 dollars) in the opinion of the committee.

This position was essentially affirmed by Dr. William L. Fisher of the University of Texas in a paper prepared for Senator Lloyd Bentsen last April. Stated Fisher: "A number of recent analyses and estimates, by a wide variety of independent groups, now conclude that the U.S. resource base is quite capable of supporting oil production at stable rates through the next five decades, and of doing so at moderate prices, if these prices are stable and technology is advanced and optimally used."

As for natural gas, Cox' committee estimated that current production rates of 17 Tcf per year could be sustained during the next fifty years at wellhead prices approximating $3.00 per Mcf (in 1986 dollars). The committee further agreed that the industry has the capability of adding ten percent growth in production during the 1990's.

Support for this position is found in DOE's 1988 natural gas survey entitled "An Assessment of the Natural Gas Resource Base of the United States." A national review panel of natural gas analysts reached the following conclusions: "More than half of the total resource evaluated in the lower 48 states, or 583 Tcf of gas, is judged economically recoverable (including finding costs) at less than $3.00/Mcf (wellhead price 1987$). An additional 174 Tcf of gas is judged economically recoverable in a price range of $3.00 to $5.00/Mcf."

It should be noted, of course, that these estimates of domestic oil and natural gas availability for the next half century rely on prices higher than current prices and on optimum application of known technologies. However, the U.S. energy consumer has experienced $25 oil and $3.00 gas in the past and may well be willing to do so again, particularly in view of the consequences developing under current energy policy that fosters lower prices. Also, there have been incentives in the tax law in the past encouraging optimum use of various reserve recovery technologies; they may well become politically acceptable again as the consequences of current energy policy are reviewed.

PROPOSED REMEDIES FOR STABILIZED DOMESTIC PETROLEUM SUPPLY

In the process of stabilizing, or even reversing, the shift from domestic petroleum production to imports now underway under current national energy policy, several political decisions must be made. First it must be realized that the domestic petroleum producing industry is competing with foreign countries and is not in a free market situation that would provide economic solutions of its own. If a new national energy policy or strategy is to be successful, it must provide programs and incentives that will economically encourage displacement of imports with domestic supply.

Other decisions must explore whether to stabilize energy prices at levels required to achieve desirable goals or to encourage through tax incentives producer behavior aimed at maximizing reserve recovery. In making these decisions, Congress and the Administration should continue to recognize the independent producer and his special role in domestic exploration and production. While his ranks have diminished by a third since 1986, with more expected to leave, the survivors are stronger and more effective. With the right economic motivation, they should be fully capable of maintaining their historic portions of exploration and production maintenance activity.

Price Stabilization. Since 1985, TIPRO has consistently maintained that an oil import fee system would be the most effective centerpiece of a new national energy policy. It is by far the simplest and most direct device there is to encourage a change in the current shift to imports from domestic production. This one economic program would lead to dramatic improvement in domestic petroleum exploration and production, encourage effective conservation in energy use and, as a useful political by-product, provide public funds to help trim the nation's budgetary deficit.

There are other price stabilization measures that have been considered from time to time, which, in TIPRO's opinion, have merit but would be less effective. For example, a variable import fee could be designed to create a desired price floor for crude oil that presumably would, in turn, influence prices for natural gas and other domestic fuels. There would be a tendency, however, for the floor to become the ceiling for all crude worldwide. Should this happen, the solution would suffer from rigidity, and there would be no public revenue generated for deficit purposes.

Other stabilization measures include a price support program for marginal or stripper oil production, such as was initiated during World War II. Another possibility might be contribution of oil by importers to fill the strategic oil reserve, which would raise the cost of imports modestly. (See Appendix D).

Another price stabilization proposal would attach a substantial environmental fee to all oil imported into U.S. coastal waters. This approach would link the problem of import growth to the problem of environmental degradation caused by tanker spills and processing of foreign oil in the nation's ports and waterways. TIPRO supports this approach as a viable option to its basic import fee proposal. (As a matter of fact, for several months the Association has vigorously opposed the imposition of a domestic oil production fee to help finance the fund incorporated in the oil spill bill now being debated in Congress; it was suggested that the fund should be financed instead by a fee on oil barrelage tankered into U.S. waters. The Association would welcome new legislative action that would, in its opinion, help set the proper precedent of assessing environmental fees on those who are causing the problem being addressed and not someone else.)

Most price stabilization measures would encourage all forms of domestic petroleum production, since their application would be universal. New oil and natural gas, established production, marginal or stripper production, and enhanced recovery would all participate. There is much to be said for this approach for it leaves to industry the task of deciding on the best ways to proceed in maximizing domestic production at the expense of imports.

Tax Code Incentives. On the other hand, tax code incentive changes under consideration in recent years have been geared to specific producer behavior, aimed at maximizing selected production sources. TIPRO supports all incentive proposals that will increase recovery effort by its members. There is concern however, that Congress and the Administration will limit the scope of its consideration in this arena because of budgetary constraints. This would tend to limit the effectiveness of the nation's new energy policy in backing out imports.

Should, however, Congress decide to turn to the tax code for domestic supply solutions, TIPRO joins other witnesses in seeking foremost corrective action on treatment of IDCs and percentage depletion under the alternate minimum tax rule. The Association specifically endorses the two changes presented by National Stripper Well Association at this hearing as the necessary underpinning for any tax incentive program.

Among the many suggestions for change in the tax code before this committee, TIPRO is especially interested in tax credit proposals for natural gas exploration activity in deeper horizons below 10,000 feet and enhanced recovery operations, along with preservation of the section 29 tax credit for tight sands natural gas production. The future capability of the domestic producing industry to reverse or at least stop the shift from domestic production to imports centers on exploring for deep natural gas reserves and on recovering a greater percentage of known oil and natural gas reserves.

In regard to the latter, TIPRO's new Applied Research and Technology Committee is developing a new definition for improved oil recovery that would add modern production techniques to the historical listing of secondary and tertiary recovery methods found in Senator Domenici's bill (S. 828) on enhanced recovery incentives. Included in this new list will be horizontal drilling activity, infill drilling programs based on geological analyses, modified waterflood projects and rotating injection-producing well patterns.

CONCLUSION

TIPRO strongly believes the domestic petroleum producing industry and the nation's petroleum reserve holdings are fully capable of maintaining current production levels well into the next century, thereby ending the shift to imports now being experienced. However, the success of this effort must rely on a new national energy policy that encourages maximization of domestic production, discourages import growth and stabilizes demand growth through a new emphasis on conservation in energy use.

No change in policy means further increase in imports that adds to the nation's burgeoning import bill, multiplies entry of foreign tankers and their threat to the environment into U.S. waters, and dramatically increases U.S. reliance on high risk Persian Gulf oil. Political decisions affirming the validity of rejuvenating domestic resources as the means of reducing or eliminating these problems under current policy are needed.

TIPRO primarily supports an oil import fee system and other measures that would provide energy price stabilization as the basic answer to the nation's energy dilemma. The Association also supports tax incentive measures that would (1), correct or improve treatment of IDCs and percentage depletion under the AMT and (2), would be sufficiently broad in application to assure best efforts by the domestic industry in securing maximization of domestic reserve recovery.

Appendix A

Excerpts from an oral statement on national energy strategy submitted by James E. Russell, President of the Texas Independent Producers and Royalty Owners Association before the Department of Energy and the Department of Interior on December 4, 1989 in Houston, Texas

In September 1989, TIPRO submitted a written statement for the record of the DOE hearing on National Er ·rgy Strategy held in Louisville, Kentucky. In that document, we outlined our proposal for a new national energy policy based on preservation of a "core supply" of domestic energy. This concept calls for quantifying the ideal levels of domestic energy production. Once objective goals have been set for the various components of this core supply, for conservation, and for imports, the nation must commit itself to achieving these goals.

Our proposal assumes that a workable energy strategy must have an objective -- a goal -- agreed to by government, the energy industry and the consuming public. This goal must be defined in terms that protect the nation's best short and long range energy and security interests, and it must be periodically revisited to assure that it will remain viable.

Decisions must then be made by the Administration and Congress to initiate actions needed to preserve and/or achieve the agreed upon objective(s). Such decisions will not be easy ones to make, but our Association strongly believes the time has come for them to be made.

Critics of the core supply concept suggest that it cannot succeed, since it would require diverse elements of the energy producing industry, the consuming public, conservationists and government officials to work together. It is becoming increasingly clear, however, that the options available to us are limited and perhaps even more problematical. For example, in the absence of a national policy that lays out alternatives to oil import increase as ways to meet future energy needs, our nation may be abdicating its policy initiatives to a small handful of Persian Gulf nations that now hold virtually all of the world's reserve crude oil producing capacity.

The obvious question arises: If Americans cannot work together to achieve desirable energy goals, how can it be presumed that they can successfully negotiate with Middle East nationals for the same purpose?

CORE SUPPLY COMPONENTS

In 1988, the U.S. consumed approximately 40 million barrels daily equivalent of energy (see Attachment #1). Generally accepted estimates indicate that the total would have been one to three million barrels daily greater had not conservation efforts been initiated during the 1977-86 decade, when energy prices were considerably higher than today.

Of this total energy consumed, domestic crude oil production provided 8.16 million barrels daily or 21 percent, while natural gas production supplied 9.17 m/b/d, or 23 percent. Oil and natural gas imports totaled 7.17 million barrels per day for 18 percent of overall supply, while domestic coal provided 8.9 m/b/d equivalent for domestic markets (22 percent) and 1.16 m/b/d for export purposes (three percent). Nuclear power contributed 2.68 m/b/d equivalent for seven percent, and other fuel sources, including hydro power, waste, wind, wood, solar and geothermal, combined for 2.55 m/b/d equivalent, or six percent of the total.

TIPRO's proposal anticipates that DOE's mission will be to analyze the interrelationship and potential of all these sources of energy, along with the contribution of conservation techniques, for meeting tomorrow's demand requirements. It is further assumed that for the foreseeable future the primary objective will be to discourage growth in oil imports through enhancement of competing fuel sources and conservation. As mentioned earlier, such enhancement will require many difficult decisions that, among other things, may involve financial commitment by all Americans.

When our Association initiated its core supply proposal some sixteen months ago, it selectively suggested production goals for domestic crude oil and natural gas, the nation's energy components provided, in part, by its membership. At that time, TIPRO pointed to the first five years of the 1980's as an ideal production period, when the home industry produced approximately 20 million barrels daily equivalent of oil, natural gas and natural gas liquids. The period was deemed ideal, because the domestic industry was able to stabilize oil import flow with its production effort.

Unfortunately, this ability has dissipated seriously since the deep energy recession that began in 1986. As the Administration well knows, the domestic producing industry has undergone wholesale dismantling of its exploration and development infrastructure. This, in turn, has reduced its contribution to the nation's energy mix by almost three million barrels daily equivalent since the 1980-85 period. At the same time, cheap energy has caused conservation efforts to wane, and the nation's energy appetite is growing again at a time when the only immediate fuel option to cover growth in demand is oil imports from the Middle East. These forces already have caused substantial increase in U.S. oil imports from the Persian Gulf source countries, particularly Saudi Arabia (see Attachment #2).

Unless this situation is reversed, TIPRO believes an inevitable crisis is on the horizon. It is conceivable that before the end of the century the whole world, including Russia's current export markets and perhaps Russia itself which is struggling with a declining energy industry, will be competing for the same reserve producing capacity barrels still available in the Persian Gulf area. In the absence of prolonged recession, the United States alone may well consume most of that capacity by the year 2000. Most experts suggest the Persian Gulf region's reserve capacity approximates 10 million barrels daily over an extended period, assuming that Saudi Arabia and its neighbors are in position to more than double production through billions of dollars investment in exploration and development activity. Since 1985, the U.S. has had to increase total import flow by an average of more than 700,000 barrels per day each year to cover decline in domestic production and increase in demand. Should that experience continue unchanged to the end of the century, our nation will consume more than seven million barrels of the presumed excess capacity, leaving only three million barrels daily or so for the growth markets in Europe and the third world to utilize.

Aside from the obvious upward thrust in energy prices such competition will cause -- straining our already serious balance of payment running deficit -- the worldwide political consequences involved could be substantial. Faced with this potential situation, it is imperative that our nation have a viable national energy policy that deals with such a fundamental issue...

SUGGESTIONS FOR NES ADMINISTRATION

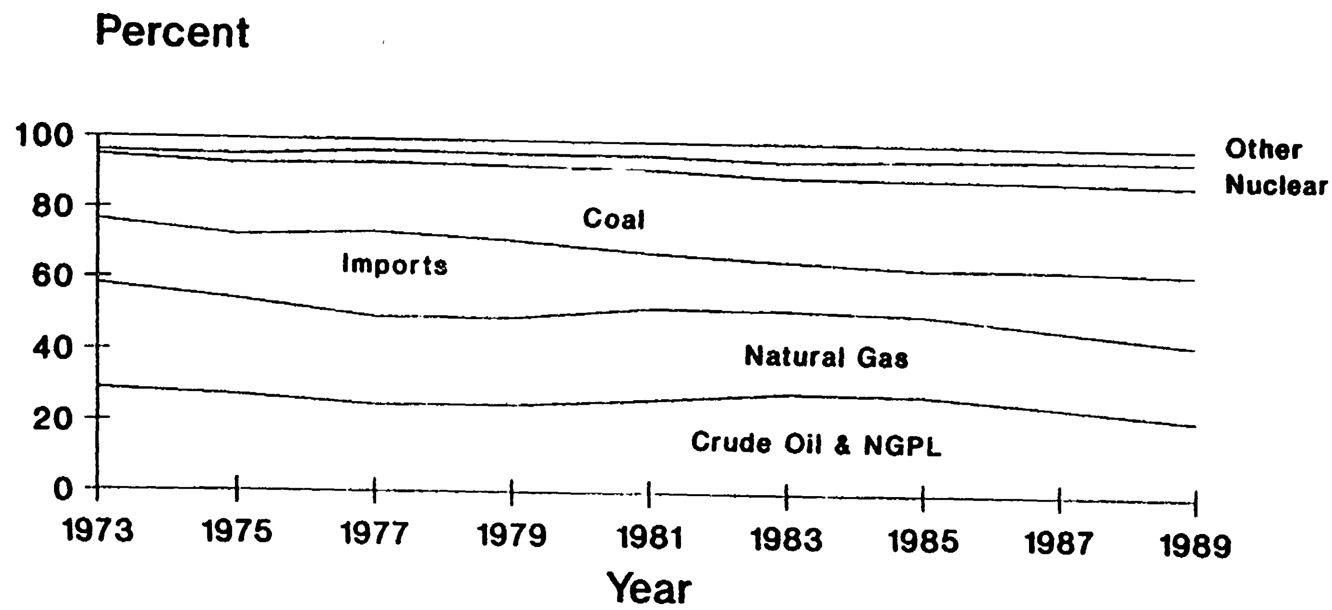
TIPRO suggests that a workable national energy strategy based on preservation of domestic supply must be periodically revisited and adjusted as needed to reflect reality or change in energy requirements. This task might best be performed by DOE with the assistance of an Advisory Board made up of government, energy industry and public representatives. TIPRO recommends that each energy source be represented, perhaps in proportion to its supply contribution.

Each energy supply source, including conservation, should be analyzed annually to map success or failure in the achievement of desirable goals. Out of this process recommendations could be made for adjusting goals or prescribing techniques to help meet failed goals. Recommendations calling for administrative action would be directed to the President, while proposals calling for legislation would be presented to Congress.

CONCLUSION

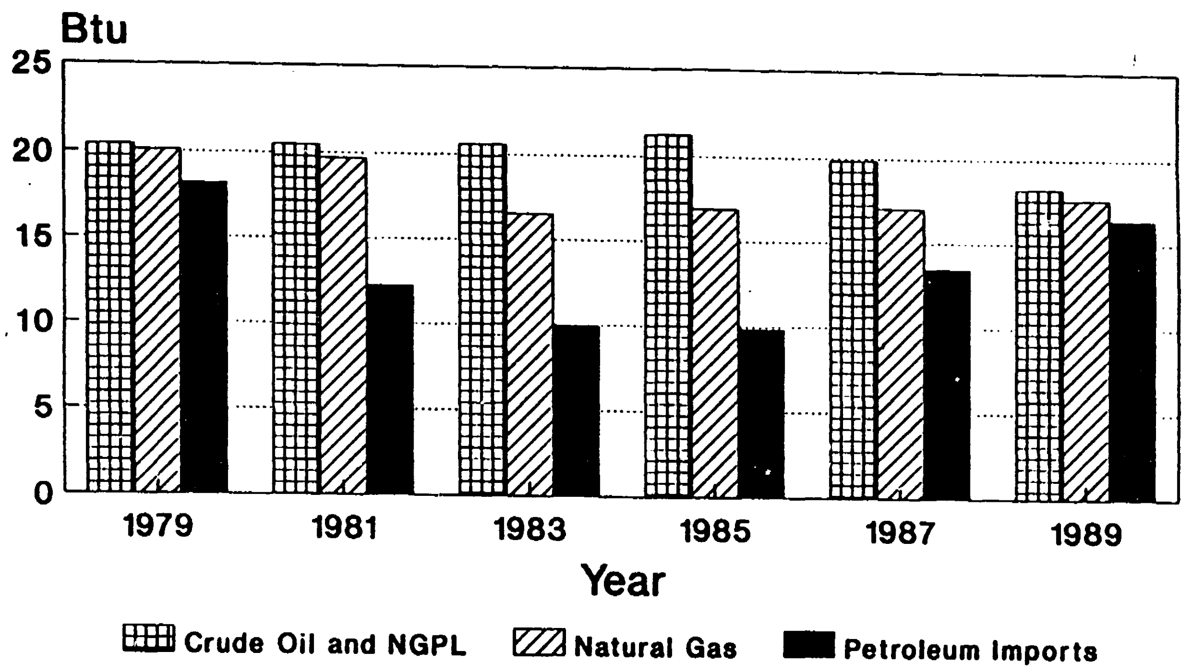
TIPRO firmly believes there is a strong need for a viable national energy strategy that will help serve the nation's best short term as well as long range economic and security interests. If properly managed, such strategy should not unduly interfere with the competitive free market system under which we operate; rather, it should represent cooperative endeavor between the government and the private sector to depress demand for imported fuel as much as is feasible. This should be an increasing concern for the United States as the entire world inexorably moves to excessive reliance on the Persian Gulf producing countries for new oil supply...

U.S. Energy Demand Components
1973-1989



Source: DOE

Domestic Petroleum Production vs Imports Supply 1979-1989



Source: DOE

Appendix D

Following is an outline of a possible program that would require oil importers to loan or grant outright oil supply to the Strategic Petroleum Reserve free of charge under prescribed circumstances. In other words, importing nations would be called upon to transfer a portion of their reserves to our reserves for emergency use in the future.

This program would be tied to the peril point concept. Assuming peril point legislation would establish that when oil imports exceed 50 percent of domestic U.S. demand they pose a peril to the nation's best security and economic interests, free transfer of a portion of imported oil to the SPR would be required once imports total 50 percent or more of domestic demand.

The amount of free transfer could be escalated as the ratio of oil imports to domestic demand moves toward 100 percent. The escalation could be tied to an objective that already exists in international agreement, namely that the United States should maintain a reserve approximating 90 days of import requirements.

To illustrate: importers of record might be required to contribute one barrel of imported oil for every 20 imported when the import ratio is in the 51-65 percent range. This contribution could be escalated to one barrel for every 15 imported should the ratio move to the 66-80 percent range. The contribution could then move to one barrel per every ten, should the ratio breach 80 percent.

Canada and Mexico could receive special consideration in this formula by exempting import volume equal to 1990 imports from the contribution computations or by some other volumetric device. However, there should be protection against undue overseas import movement through those countries attempting to circumvent the program's requirements.

Another facet of the proposal involves ownership of the SPR contributions. The barrelage could be in the form of a loan or a grant. If a loan, time of withdrawal could be at U.S. discretion based on perceived emergency needs, and the price authorized could be either the price when originally imported or the price when removed from the SPR.

There are several advantages to this proposal. First, the Administration might welcome it because it would allow the SPR to be filled without adversely impacting the U.S. budget. Secondly, it would serve to lower the cost per barrel of the SPR program, which is now estimated to be as much as $60 per barrel, and thereby maintain its political feasibility. Also, it would assure that the volume of the SPR would relate more closely to the guidelines already set for the emergency storage program. Currently, the SPR is well below the 90 day need barometer and falling steadily.

Finally, the program would provide some of the benefits of an import fee program in that importers would feel constrained to raise the cost of imports to pay for the SPR contributions. Even if the SPR contributions remained the property of importers under the proposal, the carrying and delivery costs alone would probably result in at least a $1.00 per barrel increase in imported oil cost. If the U.S. assumed ownership, the cost would double in amount.

Prepared Statement of Conley Smith

Mr. Chairman and Senators, I am Conley Smith, an independent oil and natural gas producer from Colorado and Chairman of the Tax Committee of the Independent Petroleum Association of America.

The Association represents independent crude oil and natural gas producers in all 33 states with oil and natural gas production. Independents drill the overwhelming majority of all U.S. wells, and find more than half of new oil and natural gas reserves. Independents operate as proprietorships, partnerships, or public corporations, ranging in size from very small, one-person ventures to large firms with hundreds of employees engaged in extensive oil and natural gas exploration, development and production. All independents, regardless of structure and size, have one thing in common—their profit center is the wellhead.

The problem independent producers face, and the problem the nation encounters, is that there are too few profitable domestic wellheads. That is particularly true for oil wells, as new well completions continue a precipitous decline. [See Graph 1, 2]

The IPAA is grateful to the subcommittee for turning the national spotlight once again on the oil import crisis which threatens our national security and economic stability. This hearing is very timely. The economic invasion of the American energy market continues unchecked. Our largest trade deficit—the oil trade deficit—is a greater hemorrhage of America capital than our trade deficit with Japan. Oil imports have cost the U.S. more than a half trillion dollars during the 1980s. [See Graph 3]

It's just a matter of time before America's dependence on foreign oil again forces us to pay a price in higher domestic inflation, unemployment, and hundreds of billions of dollars in new trade deficits. Meanwhile, the domestic oil and natural gas industry is facing its most difficult times. The statistics are alarming: oil imports make up almost 50 percent of U.S. consumption, drilling rig utilization is only slightly above the all-time low, U.S. crude oil production in the lower 48 states is at its lowest point since the early 1950s, and the seismic crew count, a leading indicator of future drilling activity is at a record low. [See Graphs 4, 5, 6 and 7]

The industry infrastructure has virtually collapsed. According to statistics compiled by Petroleum Information, the number of oil and gas operators of record has fallen from nearly 13,000 oil and gas operators in the early 1980s to less than 5,000 by 1989. [See Graph 8]

According to the Department of Energy, in the first quarter of this year "U.S. dependence on foreign sources of oil reached its highest in volume since the first quarter of 1980." In the first quarter of 1990, OPEC supplied 4.6 million barrels per day, over half of the total petroleum imports. That's a 17 percent increase over the first quarter of last year.

Domestic crude oil production in the first quarter of this year averaged 7.5 million barrels per day, the lowest first quarter production in over 20 years. This domestic production decrease came even though the average annual price of oil climbed more than $3.30 a barrel over the last year, from $12.57 a barrel in 1988 to $15.87 a barrel in 1989.

IPAA RECOMMENDS DOMESTIC TAX INCENTIVES AND FEE ON IMPORTS

The growing U.S. dependence on foreign oil and the downward spiral of domestic production requires an integrated energy policy to be adopted that both discourages imports and encourages domestic production. A significant piece of this policy should include a fee on imports and tax incentives for domestic production.

DOMESTIC TAX INCENTIVES

The recent higher crude oil prices have not resulted in increased exploration and drilling, which has been the case following oil price increases in the past. The primary reasons for this is the difficulty the independent oil and natural gas producers face in obtaining capital. In significant part, the problem can be traced directly to several provisions of the 1986 Tax Reform Act.

The changes made by the 1986 Act were overshadowed by the suddenness and severity of the oil price collapse beginning in January, 1986. However, just as was predicted by the industry when the Act was passed, it is now clear that new capital for exploration and production is virtually nonexistent because of the severe tax penalty imposed by the Act on high risk, capital intensive activities.

In spite of the 1986 Act's effort to limit tax shelter investing and force projects to stand on their own economics, the fact remains that the oil and natural gas economy is tax driven. One has only to look at: (1) the Section 29 credit activity which represents a significant percentage of current drilling activity, (2) the historical year-end drilling activity in the oil and natural gas business and (3) the level of Canadian drilling activity with presence of tax incentives.

A comparison of U.S. oil well completions and U.S. natural gas well completions for the 1980s supports the impact that the Section 29 credit has on drilling. Oil well completions have continued to decline over the last four years while natural gas well completions have stabilized and actually increased. [See Graph 1] It is estimated that between one-third and one-half of the current natural gas well completions will be Section 29 wells. Without the Section 29 credit, natural gas well completions would go the way of oil well completions, down.

IPAA recommends that the following domestic tax incentives should be included as part of an integrated national strategy:

- Elimination of intangible drilling costs and percentage depletion from tax preference treatment under AMT.
- A tax credit for exploratory and developmental drilling which is fully creditable against both regular tax and AMT.
- The Section 29 Nonconventional Fuel Credit should be extended and tight formation natural gas production should be reinstated as a fuel qualifying for the tax credit.
- Additional tax incentives should be provided to encourage independents to maintain marginal properties.

ALTERNATIVE MINIMUM TAX RELIEF

The Alternative Minimum Tax (AMT) is the single largest disincentive to domestic oil and natural gas drilling today. The independent oil and natural gas industry is subject to the AMT due to the inclusion of intangible drilling costs (IDCs) and percentage depletion as tax preference items, and the inability to reduce the AMT liability by the Section 29 Nonconventional Fuel Credit.

The independent sector of the U.S. domestic energy industry is perhaps more severely impacted by the AMT than any other industry subgroup. First, the oil and natural gas industry in general and the independent sector in particular is perhaps the most capital intensive industry in the U.S. Capital intensive industries bear the heaviest burden of the AMT due to the many adjustments required of "capital" outlays.

Second, AMT is a regressive tax. Capital intensive industries that are experiencing an economic downturn are particularly vulnerable to the imposition of the AMT due to resulting lower taxable income. Each of these factors, capital intensity and depressed economic conditions, renders the independent highly susceptible to AMT. The independent producer begins "going-out of business" when he produces the first barrel of oil from his first well, and he can continue in business only by drilling for and finding new oil and natural gas to replace that currently being produced and consumed. However, dollars expended by the producer just to stay in business are treated as tax preference items under the AMT.

The most notable and industry specific expenditure classification that is treated as a preference item are IDCs. IDCs are expenditures made by a taxpayer for unsalvageable items incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and natural gas. IDCs typically cannot be financed by a bank or other financial institution, but must be paid through the independent operator's internal cash flow or outside risk money supplied by investors. IDCs are analogous to ordinary and necessary operating costs in any other business, since a continuous quest for new reserves through additional drilling must occur in order to avoid continuing liquidation of the business enterprise. IDC deductibility is critical to the independent oil and natural gas industry where the key to economic survival in a risky, capital intensive business is cash flow.

When one couples the intensive capital requirements of the oil and natural gas exploration business with low product prices, the result is the crushing imposition of the AMT on independents at a time when they can least afford to pay it. This is in contrast to the major, integrated petroleum companies that rely on many profit centers—refining, transportation, chemical production, and retail service stations which are all downstream from the wellhead. In fact, lower oil prices inevitably result in higher refining profits. Further, the major oil companies have extensive holdings and operations outside the United States, which currently generate a significant portion of their profits. AMT puts an independent producer at a competitive disadvantage compared to major oil companies by causing the after-tax cost of drilling for an independent producer to be higher than for a major oil company.

Other companies can suspend capital expenditures during periods of economic downturn and still survive. Not so with the independent oil producer—he either continues to make capital expenditures or goes out of business, and many have done just that: gone out of business.

It cannot be emphasized enough that AMT is the single largest disincentive to domestic drilling today. The imposition of AMT is regressive and puts the independent producer at a competitive disadvantage. With the AMT rate being only slightly lower than the regular tax rate and the oil and natural gas industry having its largest single cost, IDCs, generally not bei deductible for AMT purposes, a large percentage of taxpayers involved in the and natural gas industry become subject to AMT. It is estimated that 75 to 80 percent of independent producers are subject to AMT. The taxing of such expenditures of hard dollars is illogical as tax policy and self-defeating as energy policy.

AMT REFORM SUPPORTED

The IPAA supports legislation to reduce the negative impact of the AMT on the oil and natural gas industry. IPAA supports the Energy Security Act of 1989 (H.R. 658, S. 234), Domestic Energy Security Act of 1989 (H.R. 664, S. 449), and the Marginal Energy Producers Incentive Act of 1989 (S. 1565, H.R. 3437), all of which provide AMT relief by either reducing the IDC tax preference, reducing the percentage depletion tax preference, or by providing for drilling and production credits which are fully creditable against AMT.

EXPLORATION TAX CREDIT SUPPORTED

The IPAA also supports a tax credit for exploration and development expenditures that is fully creditable against both regular tax and AMT. The drilling credit should cover both exploratory and developmental drilling. Although exploratory drilling increases reserves, but does little in the short term to increase production, which is our most critical need. Developmental drilling, although less risky than exploratory drilling, is still a high risk activity. In 1989 22 percent of developmental wells were dry holes. In periods of low and volatile prices the much needed capital to maintain U.S. production levels is not forthcoming. This credit would assist independent producers in raising much needed capital for exploration and development which is currently non-existent due to the severe tax penalty imposed by the 1986 Tax Reform Act.

SECTION 29 EXTENSION SUPPORTED

The IPAA supports the extension of the Section 29 Nonconventional Fuel Credit placed-in-service date and sales date along with the reinstatement of tight formation natural gas as production qualifying for the credit. This credit has and will continue to generate a significant amount of natural gas drilling and production. We note, however, that extension of this credit will have little if any impact on exploration and production of oil, the energy resource for which we are so dependent on foreign suppliers

MARGINAL WELL PRODUCTION INCENTIVES

The IPAA also supports tax incentives to encourage independents to maintain marginal properties. The U.S. is rapidly losing domestic reserves through premature abandonment of marginal properties by the major oil companies. A significant part of the United State's proved reserves are marginal properties. Once a well is plugged it is not likely to be re-opened because of the significant costs relative to remaining reserves. These tax incentive would encourage independents with lower overhead and operating costs to purchase and maintain marginal properties. The provisions supported by the IPAA include those in the Marginal Energy Producers Incentive Act of 1989 (S. 1565, H.R. 3437) and a production tax credit based on the cost of operating a marginal property.

IMPORT RESTRICTIONS

There is no free market in crude oil. Prices are being manipulated by Persian Gulf countries with the intent to dismantle the domestic petroleum industry, thereby denying the U.S. the ability to determine its energy future. All domestic energy sources—oil, gas, coal, nuclear, synthetics, and renewables—and conservation are price related and are in jeopardy.

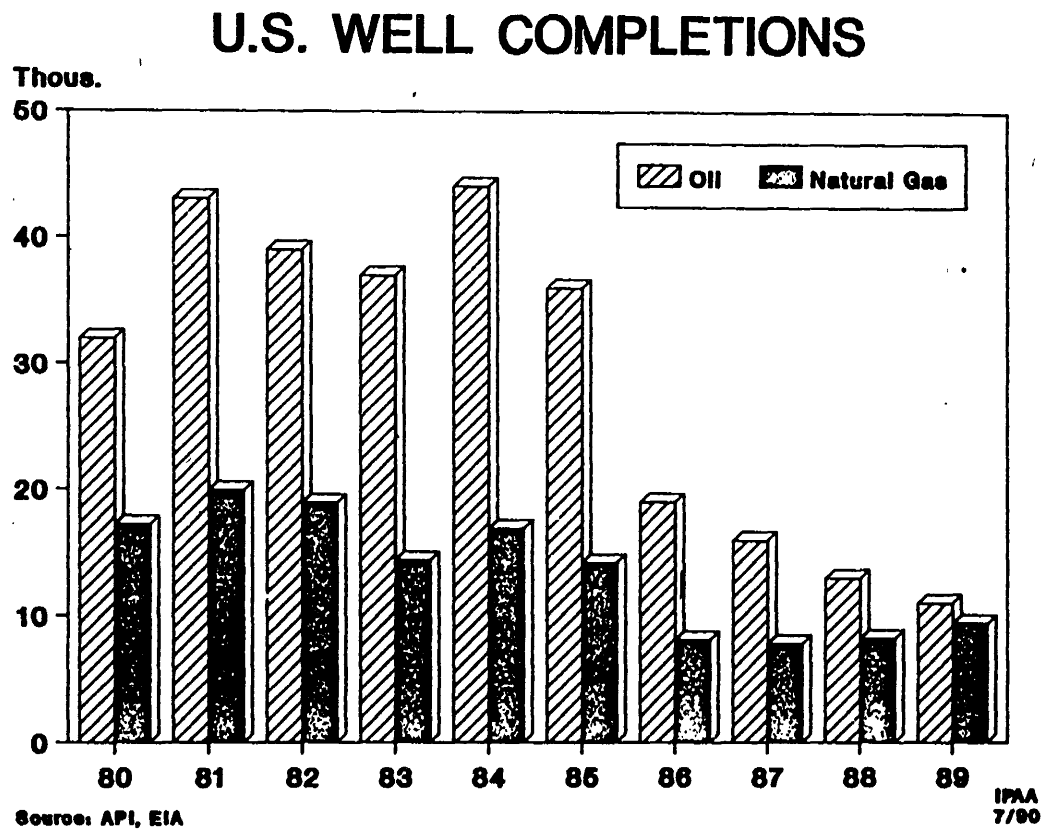
Our national security demands that the rising level of imports be stopped. A revitalized U.S. oil and natural gas ir stry is the key to winning this battle. IPAA recommends that if the domina ab OPEC countries continue to hold oil prices below the level needed for the U. to maintain adequate reserves of oil and natural gas, Congress take all appropriate action to prevent OPEC control of our energy supply. IPAA recommends the implementation of a variable import fee on crude oil and petroleum products, without exceptions or exemptions, to stabilize the price of domestic: crude oil and products at an adequate level.

BROAD-BASED ENERGY TAXES STRONGLY OPPOSED

With respect to the energy taxes proposals being discussed at the budget summit, IPAA strongly opposes any additional energy taxes. The oil and natural gas industry as a whole is one of the most heavily taxed industries when the total Federal take system is considered and should not be additionally unduly burdened. The independent oil and natural gas industry is particularly fragile at this point. As the independent producer has only the wellhead as a revenue source and is strictly a price taker, any energy tax that is placed on the wellhead or producer sales will likely be borne by the independent producer. This will only work to speed the independent's exodus from the oil and natural gas industry, further reducing domestic production, and further increasing imports. Any beneficial conservation impact of this type of energy tax would be minimal at best since much of the tax burden may be borne by the producer. This does not sound like reasonable energy policy nor reasonable national security policy.

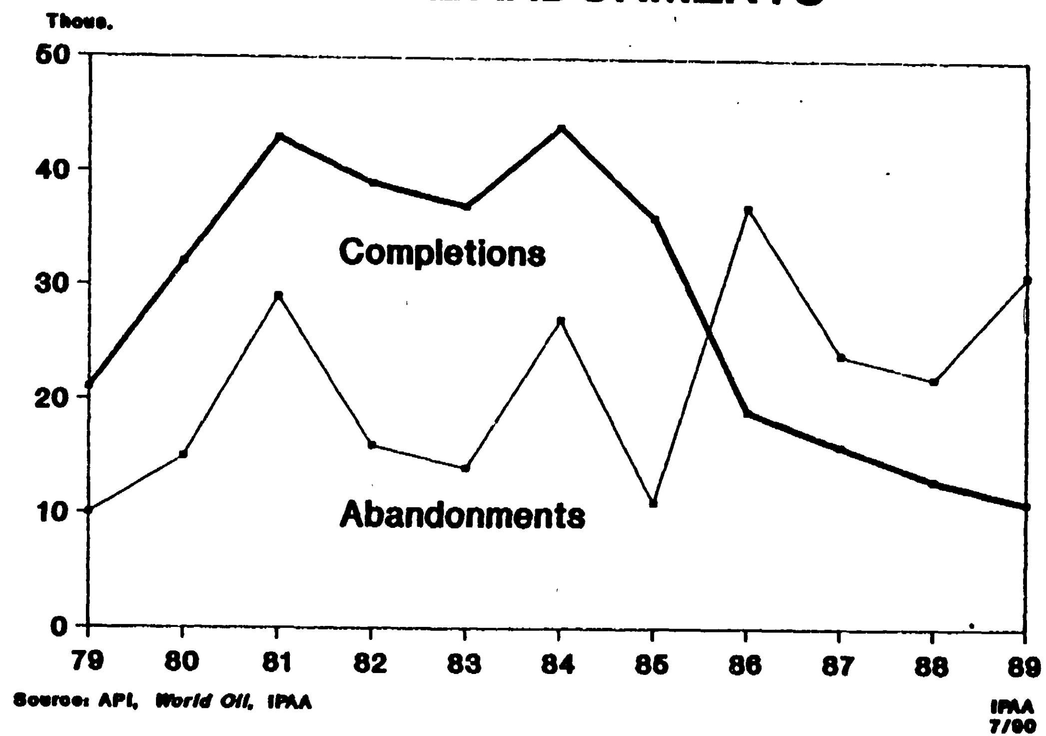
Thank you.

GRAPH 1


U.S. WELL COMPLETIONS
Thous.
50
40
30
20
10
0
Oil
Natural Gas
80
81
82
83
84
85
86
87
88
89
Source: API, EIA
IPAA
7/90

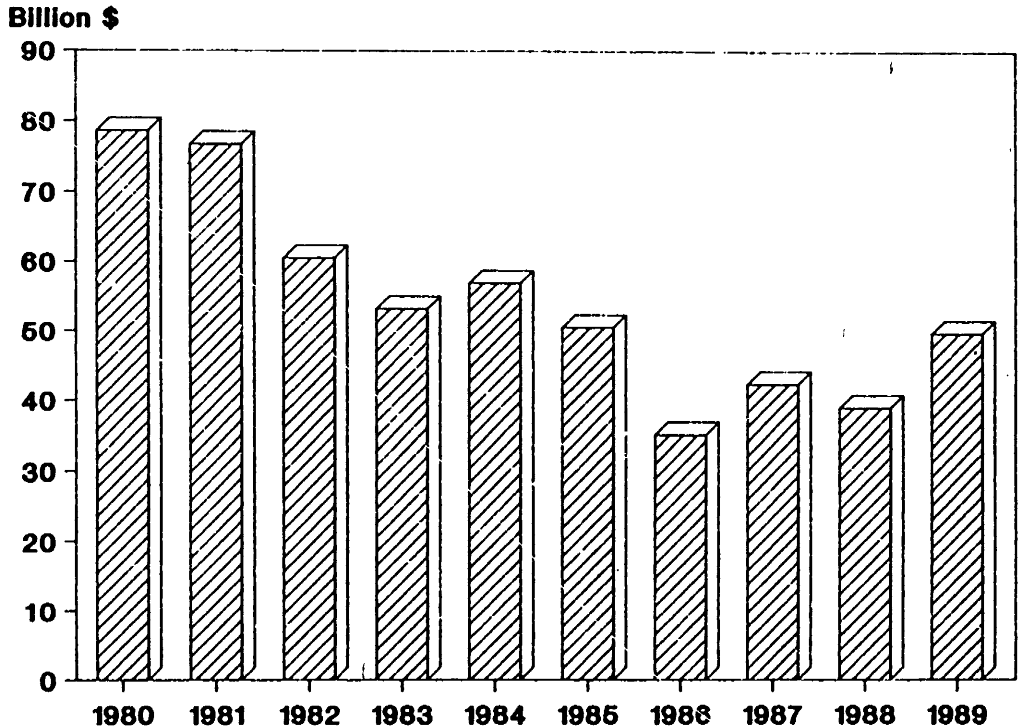
GRAPH 2

OIL WELL COMPLETIONS VS. ABANDONMENTS



GRAPH 3

VALUE OF U.S. OIL IMPORTS



Source: Department of Commerce

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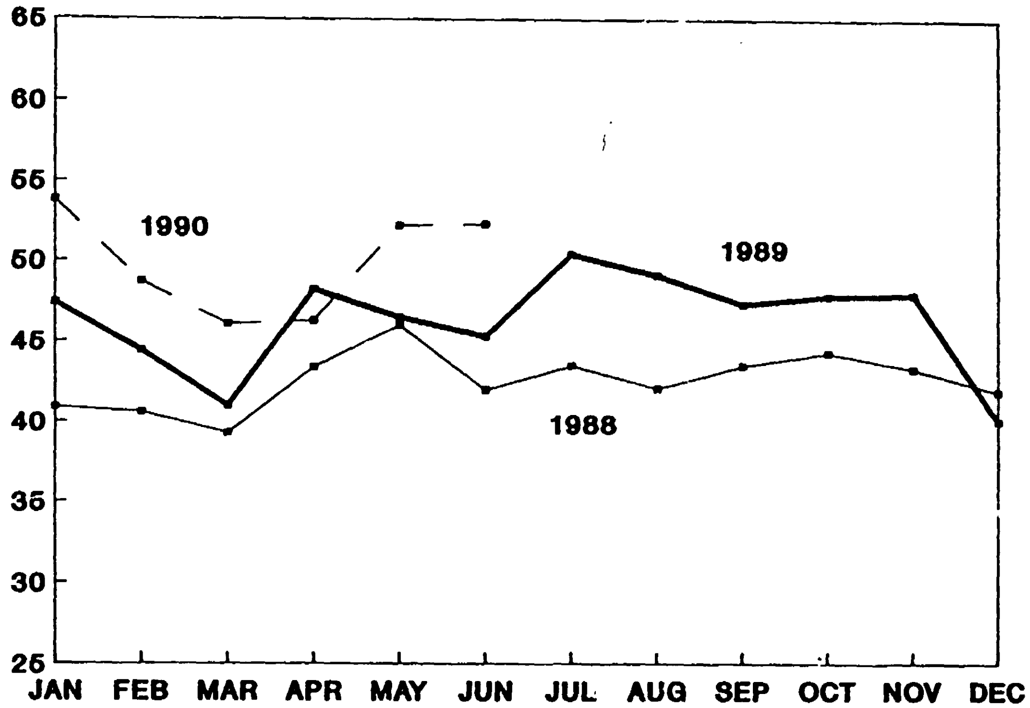
GRAPH 4

PETROLEUM IMPORTS AS % OF DEMAND



Source: EIA and API

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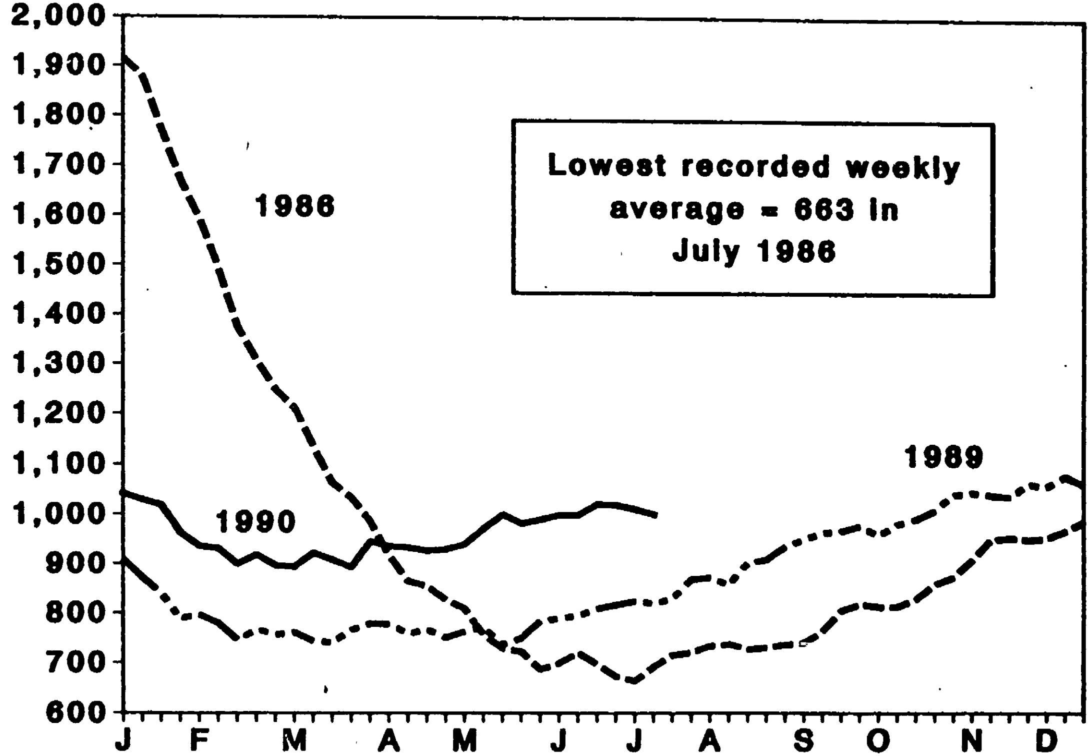
GRAPH 5

ROTARY RIGS ACTIVE



Source: Baker Hughes, Inc.

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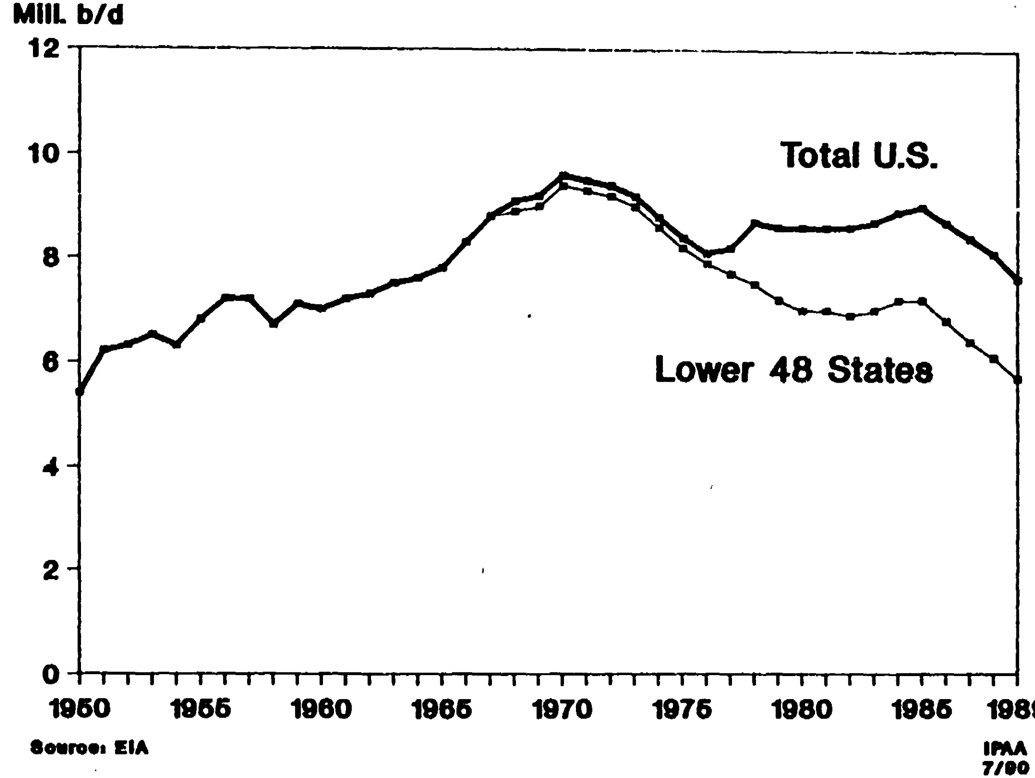
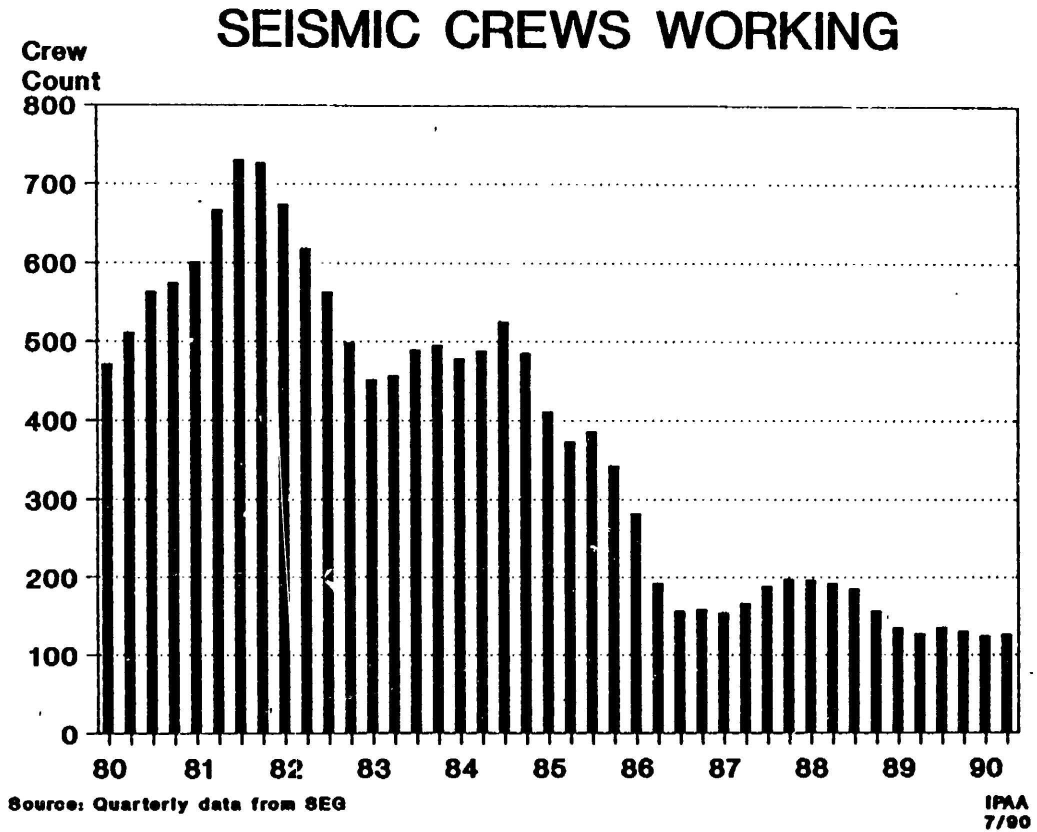
7/23/90

GRAPH 6

U.S. Crude Oil Production



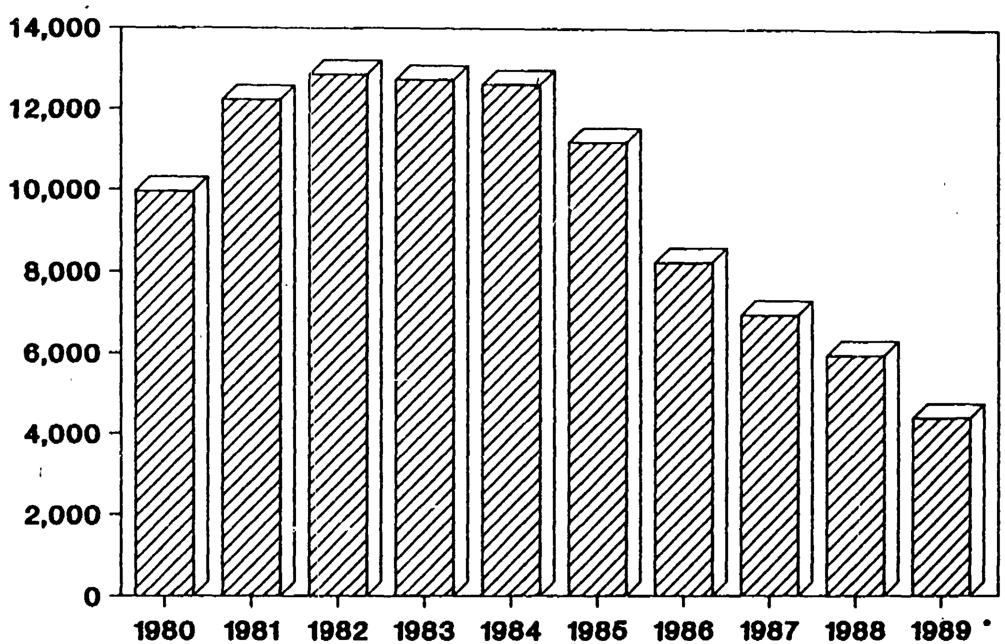
GRAPH 7



SEISMIC CREWS WORKING
Crew Count
800
700
600
500
400
300
200
100
0
80
81
82
83
84
85
86
87
88
89
90
Source: Quarterly data from SEG
IPAA
7/90

GRAPH 8

U.S. Crude Oil and Natural Gas Operators of Record



Source: Petroleum Information
* Preliminary Data

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7/90

PREPARED STATEMENT OF VITO STAGLIANO

Mr. Chairman and members of the Sub-committee, I appreciate the opportunity to testify on current conditions and future prospects in the domestic oil and gas industry. The Department of Energy believes that Federal, State and local tax policies substantially influence investment decisions in the oil industry, and as a consequence, fully supports the tax incentives proposals that the President submitted to Congress earlier this year, as part of the Administration's FY 1991 budget.

MARKET CONDITIONS AND TRENDS

Oil

U.S. crude oil production continued to decline in 1989, falling 527,000 b/d below the 1988 average. Natural gas liquids production fell 79,000 b/d, reversing a two year trend of increased production. Since the lows reached in 1986, crude prices have increased and appear to be staying in the $17 to $20 per barrel range. Future oil price are expected to increase but remain volatile. This, coupled with relatively marginal prospects for large new discoveries, explain the expected decrease in U.S. production. Reduced U.S. exploration activity, combined with high abandonment rates, indicates that further production declines can be expected. The average U.S. rig count for 1989 hit its lowest point in almost fifty years. U.S. companies are now concentrating more of their exploration activities overseas where prospects tend to be more lucrative.

Alaskan production also has declined, indicating that the Alaskan North Slope, as presently developed, has passed its peak production. Proposals to open the coastal plain of the Arctic National wildlife Refuge are on hold. Environmental concerns raised by oil spills have had a negative impact on plans for offshore oil development.

The U.S. imported 42 percent of its petroleum consumption in 1989, or over 7 million barrels per day. This figure is projected to increase in the next few years, as domestic production continues to decline. For the first 5 months of 1990, net imports have increased over 6 percent from the first 5 months of 1989.

Long term trends in U.S. oil imports are unsurprising given current market conditions, geologic prospects, and policy. The U.S. is the oldest developed oil province in this world and has been extensively explored. New reserve additions, in the form of major new fields, can only be expected from the Outer Continental Shelf (OCS) and the Alaskan Arctic.

EIA forecasts oil imports to increase from 7.2 million barrels per day (MMBD) in 1989 to between 10.4 and 14.9 MMBD in 2010, depending on oil price paths and U.S. economic growth The EIA base case projects world oil prices to rise from $17.70 in 1989 to $36.90 in 2010 (in 1989 dollars per barrel), and assuming a GNP growth rate of 4.1 percent per annum. The highest historical level of annual net imports was reached in 1977, at 8.6 MMBD, or 46.5 percent of consumption. The EIA forecast for 2010 shows import dependence of 54 to 67 percent.

Exploration and Production:

The President has decided to postpone oil and gas exploration in several environmentally sensitive offshore tracts. A broader moratorium is being considered by Congress. These leasing restrictions reflect increased concern about environmental and socioeconomic impacts of OCS development. In the event of a foreign supply disruption, leasing of the prohibited areas could be allowed to resume for national security purposes.

The recent success of horizontal drilling has been an important development for the domestic oil industry. In many cases it has significantly increased recovery rates by allowing more of the oil reservoir to be exposed to the well bore. Production from enhanced oil recovery also continues to increase, albeit slowly, despite low oil prices. These improved recovery methods should help to slow the rate of decline in oil production during the 1990's, particularly if the increases in oil prices projected by EIA materialize.

NATURAL GAS

Domestic natural gas production increased from 16.0 trillion cubic feet (TCF) in 1986 to 17.1 TCF in 1989, thereby reversing an intermittent decline that had been occurring since 1973. Total oil and gas well completions for 1989 are estimated at 28,340, the lowest level since 1973 and dramatically below the 90,030 all time record high reached in 1981. Gas wells completed in 1989 numbered 9,500.

Natural gas consumption was nearly 19 TCF in 1989, an increase of 16% over 1986 consumption. This increase is due mainly to market conditions characterized by excess supply capacity and low wellhead prices. The average annual wellhead price, which was $2.57/MCF in the 1982-1984 period, fell to about $1.71/MCF in 1989. June 1990 natural gas spot prices averaged $1.39/MCF.

Future natural gas consumption prospects are tied to deliverability and demand, and are not constrained by the domestic resource base. A 1988 DOE study of the natural gas resource base concluded that the Nation has about a 35 year supply at wellhead prices of $3.00/MCF or less. Higher prices would expand the supply significantly.

The electric utility sector is expected to be the fastest growing market for natural gas, according to EIA forecasts. From 15% of natural gas use in 1989, the utility industry is projected to increase its consumption share to 28 percent in 2010 under most economic growth scenarios.

Over the same forecast period, EIA projects wellhead prices rising from $1.71 in 1989 to between $4.57 and $6.09 in 2010, with higher consumption producing the higher price. Imports from Canada are expected to increase during the forecast period from .76 TCF in 1989 to 1.53 TCF in 2010. LNG imports are also projected to rise from less than 100 billion cubic feet in 1989 to about 800 billion cubic feet in 2010, according to the EIA.

ROLE OF TAX POLICY IN DOMESTIC OIL PRODUCTION

Mr. Chairman, earlier this year, the General Accounting Office provided to the DOE an opportunity to comment on a draft report titled "Additional Petroleum Production Tax Incentives Are Of Questionable Merit." The Department strongly objected to the conclusions of the GAO report, which was released in final form this weekl and to the methodology used in the GAO analysis.

The GAO raised a number of issues that are critical to understanding the structure of the oil and gas industry, and of the effects of tax policy on industry operations. I will discuss a number of these issues for the purpose of illuminating DOE's and the GAO's radically different perspectives.

The GAO asserts that the petroleum industry, and other producers of exhaustible resources, should be subject to the same capital recovery rules as other industries. DOE believes that oil and gas reservoirs are fundamentally different from the plant and equipment that constitutes capital for other industries, in that their replacement presents a higher degree of risk. New field wildcat wells resulted in dry holes in 86% of the cases in 1986-88, for example Few other industries are required to make investments involving such a high degree of risk.

The GAO maintains that the current regular tax and alternative minimum tax (AMT) treatment of intangible drilling costs (IDCs) constitutes an overly generous tax preference for the oil industry. DOE disagrees. Any advantage gained by the IDC deduction, for regular tax purposes, is substantially reduced by the addback provision of the AMT. The AMT is paid by three fourths of all independent producers.

Another GAO contention is that the oil industry in general pays much lower effective marginal tax rates than other industries. But according to the 1988 Energy Information Administration *Performance Profiles of Major Energy Producers*, the average in effective corporate income tax rates on the worldwide operations of U.S. energy companies continuously have exceeded those for Standard and Poor's 400 companies since 1974, except in 1968 when the rates were equal. EIA reports in the same publication that the effective income tax rate of the *domestic* petroleum industry production sector was 39% in 1988, including Federal and State income tax.

The EIA study focuses on major companies and on average tax rates, as calculated for financial accounting purpose. As pointed out by the GAO, average tax rates differ from marginal rates. However, we believe that a comparison of average tax rates, from actual data, is at least as instructive as GAO's comparison of marginal rates.

Finally, the GAO believes that producers have shifted a significant portion of their exploration activity abroad almost exclusively because of non-taxation factors, such as lower finding casts and more favorable geology. The Department of Energy believes that while geology and finding costs play an important role in the industry's investment strategies, the U.S. tax system is also a factor. Mr. Chairman, the matter of comparability of international tax policy is an important issue. We have been giving this matter considerable thought and will continue to analyze it in the months ahead. A number of factors are known about the U.S. system of "take" and about the systems used in some other countries.

When oil prices decline, the U.S. system compounds the burden on U.S. oil companies by taking an increased share of income. This results from two factors: the relatively greater U.S. reliance on a revenue-based taxation and royalty system, and the effect of the alternative minimum tax (AMT). Although royalty payments and State severance taxes are not under Federal control, they can constitute a larger share of cash flow than do income taxes, as shown in the graph at the end of my statement.

As a result of the AMT, the benefits of the tax treatment of IDC's, and their intended incentive effects are diminished. As a consequence, the oil industry may have become more cyclical and less efficient. It is for this reason that the President has proposed the elimination of 80% of the current AMT preference for exploratory IDCs.

Only in the U.S. do companies pay both a "royalty" to a landowner and a severance tax to State governments. Severance taxes range from 0.1% in California to 15% for parts of Alaska, and average 5.8% on a production-weighted basis. Some states have variable rates (Louisiana, Alaska); others have fixed rates regardless of production volume. Among the latter are Oklahoma, Texas and New Mexico. Noteworthy is the fact that *no* state varies its severance tax rate to reflect changes in the price of oil.

By contrast, the Canadian tax and royalty system, for example, has made use of temporary royalty holidays and flexibility of rates to encourage new exploration and development. The Canadian Federal Government receives no royalty payments, and the provinces set their royalty rates on the basis of production levels, current prices and well vintage.

The United Kingdom has rescinded the use of royalty payments on new leases in order to encourage exploration, and has placed a limit on the amount of petroleum revenue taxes (PRT) payable in order to promote new fields and efficient drainage of old fields.

The U.K. system also exempts from the PRT up to the first 77 million barrels of oil produced in each new field.

Norway's system of "take" is based solely on income and special profits taxes, with no revenue based taxes or royalties for new fields. Ecuador levies no royalties but collects its share of revenue from oil production, less reimbursed costs.

Another provision of the U.S. tax code that reduces the intended incentive for exploration, when oil prices are low, is the 50% net income limitation on percentage depletion for independent producers. This tax reduces benefits when they are most needed; that is, when income is low due to increased costs, falling production, or lower oil prices. This provision encourages early abandonment of marginal wells that, by definition, have low income.

The best evidence in favor of the President's energy tax proposals is industry's performance since the 1985 oil price collapse. Since 1985, U.S. exploration activity has declined far more rapidly, and has remained lower, than exploration in other countries. Since the relative difference in geology has not changed appreciably during this period, and since relative finding costs have actually *declined* in the U.S., it is reasonable to assume that cost-effective tax changes can encourage an increase in U.S. oil exploration and production.

On the investment side, in response to rising oil price expectations in 1989, domestic exploration and development expenditures in 1990 are expected to be about $13.5 billion, an increase of about 7% over the previous year. Spending overseas by U.S. majority owned affiliates is expected to rise 25%, to nearly $8 billion. This recovery comes after the precipitous decline in exploration spending that occurred between 1981 and 1988, when crude oil lost over 60% of its value. In 1981, domestic exploration expenditures were nearly $40 billion, and overseas spending was nearly $10 billion. Cost-effective modifications of tax policy can play a role in improving the relative profitability of domestic investments.

Another indication of the relatively large decrease in domestic exploration is found by comparing domestic and international rig counts over the past 14 years. The U.S. rig count is far more sensitive to prices than the international rig count. Since 1981, when oil prices reached their peak, the rig count in the

U.S. has dropped by 78 percent, while the international rig count has declined by 37 percent. The current system of "take" tends to magnify the effect of oil prices by imposing greater effective tax rates on low income producers than on high income producers. Thus, the combined State and Federal tax and private royalty payments may likely have discouraged U.S. exploration activity.

Historically, large increases in energy prices have spurred rapid growth in drilling investments. However, as the 1990 EIA *Annual Energy Outlook* points out, the oil price volatility that characterized the 1980's "has had a chilling effect on the responsiveness of investment to price changes." This is particularly true for independents who are far more reliant on external financing than are the majors. Prospects for increased drilling could nevertheless improve under the increased oil prices projected by EIA for the 1990's.

Summary

Many countries have responded to the drop in oil prices by reducing their "total take" in order to maintain a competitive oil and gas industry. Unlike the U.S., Canadian provinces offer progressive royalty rates that vary with price, production volume or costs. Norway has eliminated royalties on new licenses altogether. The United Kingdom allows no income taxes to be collected until all investment costs are repaid, thereby substantially decreasing investment risk.

The U.S. has taken no action in response to the decline in oil prices, other than to repeal the already useless windfall Profits Tax. But the U.S. substantially reduced corporate tax rates in 1986.

The President's Tax Incentives Proposal

In February 1989, in order to begin the process of recovery in the U.S. oil and gas industry, the President submitted to Congress a number of tax incentives to encourage exploration for new oil and gas fields, and to encourage continued operation of existing fields. The program includes five proposals:

- Repeal of the prohibition on use of percentage depletion on certain transferred properties;
- A provision permitting independent producers to deduct from their income for alternative minimum tax purposes a larger portion of their exploratory drilling costs than currently allowed;
- An increase in the property net income limitation for the percentage depletion allowance;
- A temporary tax credit for certain exploratory drilling costs; and
- A temporary tax credit for new enhanced oil recovery projects.

The first proposal, repeal of the transfer rule, will aid in the preservation of existing production by extending the productive lives of numerous marginal wells, owned by major producers, and slated for abandonment because of high operating costs. Repeal would encourage the acquisition of marginal wells by independent producers, who could profitably operate the wells because of lower overhead costs and because of their access to the percentage depletion allowance.

The abandonment of existing wells is a critical problem. Over 18,000 wells are abandoned in the U.S. each year, making their remaining in-ground reserves virtually impossible to recover. It is important to recognize that only about one-third of the oil in existing fields is normally recovered. That leaves over 300 billion barrels still theoretically available, a volume which represents about twice as much oil as total U.S. cumulative oil production to date.

Once a well is abandoned, it is prohibitively expensive to unplug it and resume production with current technology. Furthermore, in many cases once the well ceases product ion, it is not possible to resume conventional production at any cost, due to infiltration of water into the reservoir. Repeal of the transfer rule, as well as the tax credit for new enhanced oil recovery projects and the proposed increase in the net income limitation, will help to discourage the premature abandonment of existing wells.

The second proposal is a modification of the treatment of exploratory intangible drilling costs (IDC's) for alternative minimum tax (AMT) purposes. Intangible drilling costs represent the portion of drilling costs with little or no salvage value. These costs usually amount to 75 to 85 percent of total drilling expenditures. Currently, independent producers can fully deduct IDC's when computing income subject to regular income taxes. However, an estimated three-fourths of all independents are now subject to the AMT. The AMT substantially reduces the advantage of deducting IDC's because a large part of IDC's is often added back to the producer's income in calculating the AMT.

The independent non-integrated producer is the most susceptible to swings in oil prices. If the proposal to modify IDC treatment were adopted, it would encourage additional exploratory drilling by independent producers, who historically account for an estimated 90 percent of all exploratory wells each year. The proposal would increase discoveries of new oil fields, which would add to our reserve base. The additional drilling induced by this proposal could eventually add an estimated 21,000 to 28,000 barrels per day of production.

The third proposal would benefit producers by allowing full use of percentage depletion by taxpayers with incomes that are low relative to their available depletion. The President's proposal recommends increasing the property income limitation. The advantage of this proposal is that the revenue specifically assists properties with low net incomes—that is, marginal properties that may be close to abandonment.

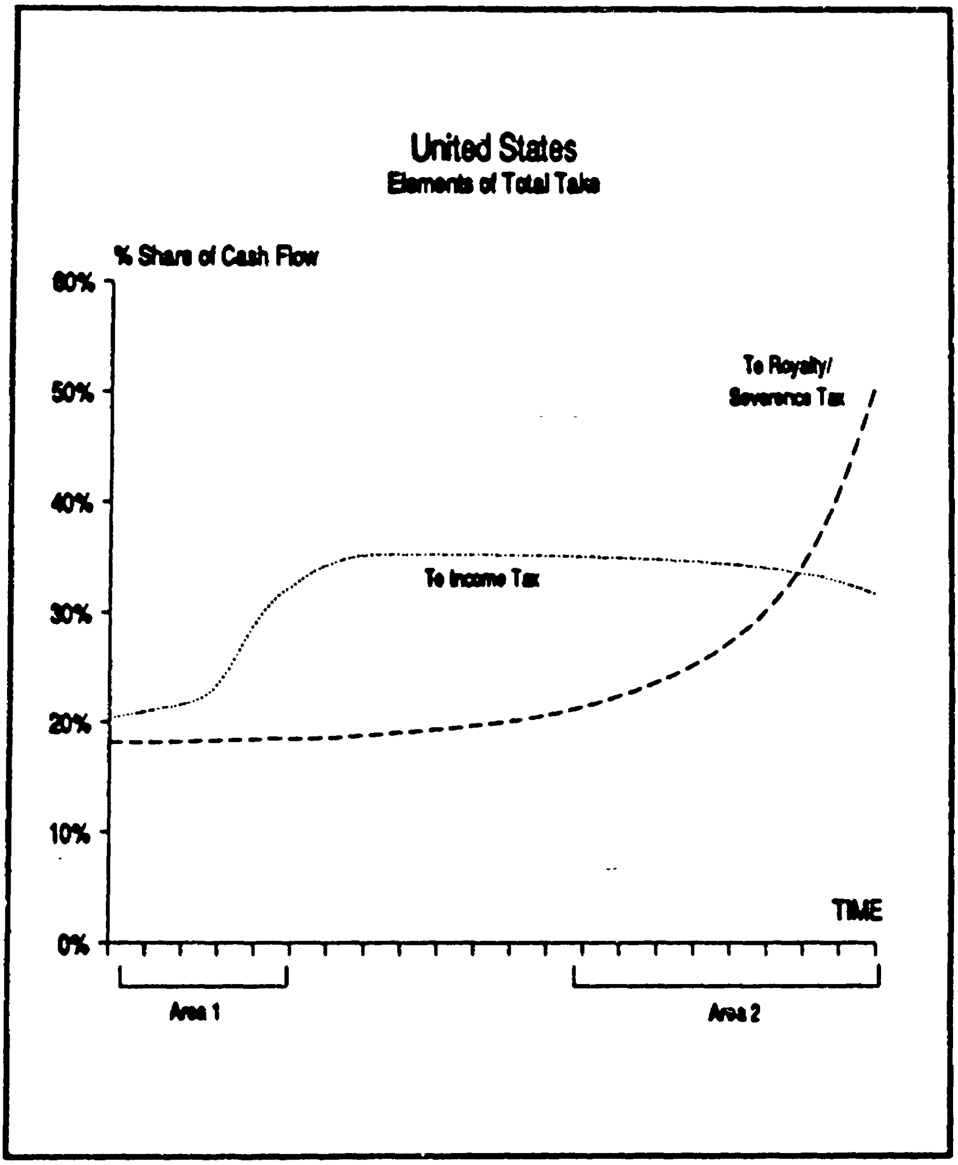
The fourth proposal accelerates the recovery of capital outlays for exploratory drilling, reduces the net cost of finding oil and gas reserves, and provides a new source of funds which can be reinvested in domestic exploration. As a result of the credit, the overall level of geological and geophysical expenditures and development drilling will also increase.

The President's fifth proposal, which establishes a temporary tax credit for new enhanced oil recovery projects, would increase the level of new EOR production by approximately one-third.

The five proposals, taken together, could add an estimated 172,000 to 196,000 barrels per day of domestic production. This added production would reduce tanker traffic by approximately four large tankers (200,000 dead weight tons) per month. This added production would represent a reduction in our trade deficit of $1.1 billion to $1.3 billion per year (assuming $18/bbl oil).

Mr. Chairman, we believe that the President's proposals deserve Congressional attention because they will help to slow the steady deterioration of domestic oil production. We defer to the Department of the Treasury on the estimated budget impacts of these proposals, but believe they are cost effective.

This concludes my testimony and I shall be happy to answer any questions.



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PREPARED STATEMENT OF ROBERT R. WOOTTON

Mr. Chairman and Members of the Subcommittee: I am pleased to have this opportunity to present the views of the Treasury Department on steps that can be taken to increase domestic energy production and reserves within current budgetary restraints.

Recognizing the importance of maintaining a strong domestic energy industry, the Administration has consistently called for the Congress to enact measures to stimulate domestic exploration and production. The Administration's budgets for both fiscal year 1990 and fiscal year 1991 contain a number of tax incentives specifically targeted to the domestic energy industry. These incentives are intended to address the drop in domestic exploratory drilling that has occurred during the past decade and the continuing loss of production from mature fields and marginal properties.

From the late 1970s to the mid-1980s the United States enjoyed a significant decline in oil consumption while domestic production remained about constant. More recently, however, consumption has risen and oil production has begun to decline. U.S. domestic oil production has fallen by about 15% since 1986, according to data supplied by the Department of Energy.

The tax incentives proposed in the Administration's budget are intended to respond to this unfavorable trend in domestic production. I would now like to review the specific budget proposals in more detail.

SUMMARY OF BUDGET PROPOSALS

The budget for fiscal year 1991 again proposes the enactment of a program of oil and gas tax incentives first proposed in the Administration's budget for fiscal year 1990. Consisting of five separate proposals, the program has two major objectives: increasing domestic exploratory drilling and sustaining production from mature and marginal fields.

While other approaches have been proposed, as evidenced by the variety of legislative proposals introduced during this Congress, the reality of the current budget environment requires that every proposal be evaluated in terms of its cost. The Administration's proposals offer real help in meeting energy independence goals within the constraints of responsible fiscal policy.

The Administration's proposals would amend the Internal Revenue Code to: (1) allow a temporary 10% tax credit for the first $10 million of expenditures (per year per company) on exploratory intangible drilling and development costs (IDCs) and a 5% credit for the balance; (2) allow a temporary 10% tax credit for all capital expenditures on projects that represent new applications of tertiary enhanced recovery techniques to a property; (3) eliminate the "transfer rule," which discourages the transfer of proven properties to independent producers and royalty owners by prohibiting percentage depletion after such a transfer; (4) increase the percentage depletion deduction limit for independent producers and royalty owners to 100% of the taxable income from each property; and (5) eliminate 80% of current alternative minimum tax (AMT) preference items generated by exploratory IDCs incurred by independent producers. The temporary tax credits would apply against both regular and minimum tax liability (although the credits could not, in conjunction with all other credits and net operating loss carryovers, eliminate more than 80% of tentative minimum tax in any year). The credits would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for a calendar year.

EXPLORATORY DRILLING

New discoveries of domestic oil and gas are needed to increase reserves and allow for long-term growth of domestic energy production. Industry and government data show that the level of exploratory well drilling has fallen about 70% in recent years, and new additions to oil reserves in 1988 (the latest year for which data are available) were at the second lowest level ever reported.

The Administration's budget provisions that are aimed at increasing exploratory drilling are the tax credit for exploratory IDCs and the alternative minimum tax relief for exploratory IDCs. The proposed tax credit would serve to reduce the cost of exploratory drilling, thereby encouraging more activity. Exploratory drilling must be encouraged if new reserves are to be found.

Current law treats the deduction for IDCs on successful oil and gas wells as an item of tax preference for purposes of the individual and corporate alternative minimum taxes, to the extent that the taxpayer's excess IDCs exceed 65% of the taxpayer's net income from oil and gas properties. Excess IDCs are the amount by which the IDC deductions for the taxable year exceed the deductions that would have been allowed had the IDCs been capitalized and recovered over 120 months or, at the taxpayer's election, through cost depletion. Percentage depletion is also an alternative minimum tax preference item to the extent it exceeds a taxpayer's basis in the property.

The rationale for treating excess IDCs as an item of tax preference begins with the observation that IDCs generally fit the description of a capitalizable cost—that is, a cost which creates a benefit extending beyond the year in which it is incurred. Following the capitalization approach, IDCs would generally be added to the cost of the properties whose value they enhance and recovered through depletion or depreciation over a period of years. IDCs may be viewed as an item of tax preference to the extent that the tax law allows a current deduction in excess of the amount that would be allowable if the IDCs were capitalized.

For taxpayers subject to the alternative minimum tax, the deductibility of intangible drilling costs for regular tax purposes is of limited benefit. The decline in oil prices in recent years has had the effect of reducing the taxable income of independent producers, and many have become subject to the alternative minimum tax. Thus, independent producers, who have historically drilled a majority of our exploratory wells, receive limited benefit from the deduction for IDCs. Although we recognize the rationale for treating excess IDCs as items of tax preference, the Administration believes that relief from the alternative minimum tax in the limited case of exploratory IDCs will provide a real incentive for independent producers to undertake exploratory activities at an acceptable cost in foregone tax revenues.

MARGINAL AND ENHANCED PRODUCTION PROPERTIES

Marginal Properties. The Administration believes that discouraging abandonments of marginal properties is an important objective of energy policy. Production from a well is normally lost forever upon its being abandoned, because the well is permanently cemented and requires redrilling to reopen. Stripper well abandonments are reported by the Interstate Oil Compact Commission to have increased from 7,668 in 1979 to 17,423 in 1988. Keeping marginal properties in operation will enhance current oil and gas production and also help to preserve the industry infrastructure that our nation needs to maintain an appropriate degree of energy independence.

The current percentage depletion rules allow certain taxpayers to deduct 15% of the gross income from an oil- or gas-producing property in each taxable year. The amount deducted cannot exceed 50% of the taxable income from the property for the taxable year, computed without regard to the depletion deduction (the "net income limitation"). This restriction is most likely to affect marginal wells, where operating costs are high relative to revenues. The Administration's budget proposals would encourage continued production from these wells by increasing the net income limitation to 100% of the taxable income from the property.

Under current law, only independent producers and royalty owners may use percentage depletion, for up to 1,000 barrels of average daily domestic crude oil production, or an equivalent amount of domestic natural gas. Integrated producers, those that refine or retail oil or gas, must use the generally less favorable cost depletion method. The "transfer rule" prevents the transferee of a proven oil or gas property from claiming percentage depletion with respect to production from the property. The rationale originally offered for the transfer rule was to prevent integrated producers from benefiting from percentage depletion by selling proven properties to independent producers. However, the transfer rule applies equally to transfers of property among independents in situations where the transferor could itself claim percentage depletion. In addition, the transfer rule creates a disincentive for the transfer of marginal properties to those who, because of specialized expertise, economies of scale or other operating efficiencies, or greater capacity to use the depletion tax benefits, would be more likely to keep the property in production. In its budget proposals, the Administration recommends repeal of the transfer rule.

Enhanced Recovery Properties. The Internal Revenue Code currently provides a deduction for the cost of tertiary injectants used as part of a tertiary recovery method. A tertiary recovery method includes any method enumerated in subparagraphs (1) through (9) of section 212.78(c) of the June 1979 energy regulations. A taxpayer may also use any other method approved by the Secretary.

While the deductibility of injectants is undoubtedly of some benefit to tertiary projects, the Administration believes more needs to be done. By providing a 10% tax credit for all capital expenditures in new tertiary enhanced recovery projects, the Administration's budget would encourage investment in such projects. As more such projects are undertaken, technology should improve and recovery rates should rise.

NONCONVENTIONAL FUELS CREDIT

Under current law, fuels produced from certain nonconventional sources qualify for a production tax credit. Eligible fuels must be produced from a well drilled or a facility placed in service before January 1, 1991. Eligible fuels include gas from a tight formation, or "tight sands gas," as long as the gas is subject to price regulation. Under a 1988 U.S. Supreme Court opinion upholding an order of the Federal Energy Regulatory Commission, and other subsequent developments, the price of virtually all tight sands gas is unregulated and therefore is not eligible for the tax credit.

The 1989 budget reconciliation provisions approved by the Finance Committee would have (i) caused production of tight sands gas to be eligible for the credit even if the gas is not price regulated and (ii) extended the wells drilled/facilities placed in service date to January 1, 1993. The estimated 5-year cost of this provision was approximately $685 million. Similar proposals are included in S. 234 and S. 449.

It is likely that Congress originally specified price controls as a precondition to the credit for tight sands gas on the assumption that the regulated price would be below the price that would exist in an unregulated market, and that in such circumstances a special incentive was needed to encourage the production of gas from this particular source. Because the price of tight sands gas is now virtually unregulated, this justification for the tax credit no longer exists. Each of the proposals relating to the tight sands gas credit is relatively costly. The budget reflects a choice of other policies as more directly related to energy independence goals than proposed enhancements or extensions of this credit. Enactment of any of the various proposals relating to this credit would reduce the funding available in the budget for the proposals offered by the Administration.

CONCLUSION

We believe that the Administration's budget proposals are a cost effective means of stimulating exploratory drilling and preserving marginal and tertiary production. We look forward to working with the Subcommittee, the full Committee, and the Congress in enacting legislation consistent with sound fiscal policy to promote energy independence.

I appreciate the opportunity to appear before your Subcommittee today. I will be pleased to answer questions at this time.

Attachment.

DEPARTMENT OF THE TREASURY
WASHINGTON

April 19, 1990

Mr. Richard L. Fogel
Assistant Comptroller General
United States
General Accounting Office
Washington, D.C. 20548

Re: GAO Report -- Additional Petroleum Industry Tax Incentives Are of Questionable Merit

Dear Mr. Fogel:

Thank you for the opportunity to provide comments on the report of the United States General Accounting Office ("GAO") "Additional Petroleum Industry Tax Incentives Are of Questionable Merit."

The report examines several tax incentives for the petroleum industry, including incentives included in the Administration's FY 91 budget. The report recognizes that such incentives would, to a certain degree, increase oil and gas exploration, development, and production and thereby improve U.S. energy security. However, the report questions whether additional tax incentives for the petroleum industry are as cost effective as other measures, including continuing to build strategic oil stocks, such as the Strategic Petroleum Reserve, encouraging conservation, and developing alternative fuels.

The Nation's Energy Goals

The GAO undertook this report at a time of serious concern voiced by the Congress, the Administration, and the business community over whether the nation has adequate energy security. The GAO report recognizes the widely held view that increased dependence on foreign oil leaves the nation vulnerable to potential foreign supply disruptions. The Administration believes that a balanced approach represents the best means of achieving increased energy security. The Administration's FY91 budget energy proposals, many of which are consistent with recommendations made by the GAO report, seek to increase energy security through a combination of non-tax measures and tax incentives. The tax incentives are an important element of these proposals. Thus, we disagree with the conclusion of the GAO study that it would be inappropriate at this time to enact any tax incentives for the domestic oil and gas industry.

The Administration's Proposed Tax Incentives

The Administration's FY91 budget proposed four tax incentives to encourage exploration for new oil and gas fields and the reclamation of old fields: (1) A temporary 10 percent tax credit for the first $10 million of expenditures (per year, per company) on exploratory intangible drilling costs and a 5 percent credit on the balance of exploratory drilling costs; (2) A temporary 10 percent tax credit for all capital expenditures on new tertiary enhanced recovery projects (i.e., projects that represent the initial application of tertiary enhanced recovery to a property); (3) Repeal of the "transfer rule," which prohibits percentage depletion for properties acquired by, or transferred to, an independent producer after the property is shown to have oil or gas reserves, and an increase in the percentage depletion deduction limit for independent producers to 100 percent of the net income of each property; and (4) Elimination of 80 percent of current AMT preference items generated by exploratory intangible drilling costs incurred by independent producers. The two tax credits would be phased out if the average daily U.S. wellhead price of oil is at or above $21 per barrel for an entire calendar year. The estimated revenue cost of these four incentives is $400 million to $500 million per year.

Exploratory Drilling. The Administration recognizes the importance of raising the level of domestic exploratory drilling. The level of proven domestic reserves is closely related to the level of domestic exploratory drilling, which has fallen by 70 percent from recent levels, largely due to uncertainty concerning low world oil prices. In addition, over the same time period, development drilling has increased 20 percent, resulting in a substantial decline in existing domestic oil and gas reserves. Special tax incentives are appropriate to encourage higher levels of exploratory drilling, that will ultimately lead to increased domestic reserves. Higher levels of exploratory drilling activity also would provide continuing opportunities for skilled geologists and drilling contractors. The GAO report does not address the fact that the proposal would help preserve the resource base and the human capital required for the nation to maintain a reasonable degree of energy independence. In addition, the report does not evaluate the additional reserves that may arise from the credit for exploratory drilling and the credit for tertiary enhanced oil recovery. By focusing solely on increased production, the report ignores the enhancement to our national energy security resulting from the addition of reserves from increased exploratory drilling.

Enhanced Oil Recovery. A temporary tax credit for new tertiary enhanced recovery projects would encourage the recovery of known energy deposits that are currently too costly to produce. The proposal would encourage the development of better enhanced oil recovery ("EOR") methods. Although the GAO report asserts that the research and experimentation credit already provides sufficient incentives to discover new EOR technology, the Administration believes that a temporary tax credit would serve both to further encourage the discovery of new technology and to stimulate hands-on projects and actual production. The goal of developing EOR technology will become more important to our nation's energy security as more of our production derives from mature oil fields.

Marginal Properties. An important goal of the Administration's proposals is the preservation of production from marginal properties. The transfer rule discourages the transfer of producing wells that are uneconomic in the hands of their current owners (and thus likely to be abandoned) to those who may be more efficient, more willing to bear current losses, or better able to use the percentage depletion benefits (and thus able to continue operation of the property). Current law also provides that percentage depletion may not exceed 50 percent of the net income of a property calculated before depletion. The 50 percent net income limitation may significantly reduce the benefits of percentage depletion for production from properties generating a small amount of net income. Raising the net income limit to 100 percent would allow some oil producers to claim greater depletion deductions, thus encouraging them to continue to operate marginal properties.

The GAO report recognizes that incentives of the type proposed by the Administration are likely to enhance the viability of marginal properties. The report also recognizes that once a marginal property is shut in, the production is lost because it will probably never be economic to redrill the property. The Administration believes that preserving production from marginal properties justifies the revenue costs of the tax incentive.

Conclusion

The Administration believes that the proposed tax incentives would encourage exploration for new oil and gas fields and the reclamation of old fields. Although the GAO report alleges that the proposed incentives are not cost effective, many of the benefits that result from the proposals are difficult to measure precisely, and thus to reflect adequately in such comparisons. For example, the proposed incentives would strengthen the financial health of smaller independent producers, that have long been recognized as leaders in exploratory drilling. It is not clear how such a benefit could be quantified.

In addition to the proposed tax incentives, the Administration's FY91 budget includes non-tax measures that would improve the Nation's energy security. For example, the Administration proposes to fill the Strategic Petroleum Reserve in 1991 at a daily average rate of 59,000 barrels per day. This program seeks to decrease the vulnerability of the United States to disruptions in world petroleum markets by maintaining a crude oil stockpile to be used in the event such disruptions occur. The budget also includes a request for $1 billion for 1991 for new research and development initiatives for renewable and fossil energy, energy conservation initiatives, clean coal technology, and oil and gas geoscience.

The Administration's budget proposals represent a balanced approach to our nation's energy needs. The budget proposes to expend resources to fill the Strategic Petroleum Reserve, to hasten the development of alternative energy technologies, to encourage energy conservation, and to stimulate the nation's domestic oil and gas industry. The proposals to provide additional tax incentives for the domestic oil and gas industry serve important purposes and are an essential component of the balanced approach to improving U.S. energy security.

Yours sincerely,

Robert R. Wootton
Tax Legislative Counsel

COMMUNICATIONS

STATEMENT OF THE APPALACHIAN ENERGY GROUP

Mr. Chairman, my name is Steve Williams. I represent the Appalachian Energy Group (AEG) and am President of Petroleum Development Corporation. I want to thank you for this opportunity to testify in favor of the extension of the nonconventional fuel source tax credit in Section 29 of the Internal Revenue Code of 1986 and restoration of the credit to gas produced from tight sands.

The Appalachian Energy Group was formed to provide a forum for the exchange of information among the oil and natural gas producing associations within the Appalachian Basin. AEG member associations are the following: the Independent Oil & Gas Association of New York, the Independent Oil & Gas Association of West Virginia, Kentucky Oil and Gas Association, the Ohio Oil & Gas Association, the Pennsylvania Natural Gas Association, the Pennsylvania Oil & Gas Association, and the Virginia Oil & Gas Association. Our members represent thousands of independent oil and natural gas companies that together produce virtually all of the oil and natural gas in the Appalachian Basin. Our members believe that extension of Section 29 credit and restoration of he credit to gas produced from tight sands is crucial to the economic future of the oil and natural gas industry in the Appalachian Basin and is an essential prerequisite to the efficient and effective development of America's nonconventional fuel resources.

The AEG supports legislation which would:

1. Reinstate the tight sands credit.
2. Make the Section 29 credit permanent subject to the current phase-out if gas prices rise.
3. Allow the Section 29 credit to be applied against the alternative minimum tax (AMT).

Mr. Chairman, I could talk for a long time about how important these provisions are to the producing industry in the Appalachian basin, but my presence here is obvious testimony to that fact. Instead I want to focus on why adoption of these provisions are important to, and worth the cost to, the country in general.

I think there are at least four reasons why these provisions deserve your consideration and support:

1. Additional gas supplies developed as a result of tax credit will greatly reduce prices to consumers of natural gas throughout the country.
2. By maintaining, or even increasing, the level of drilling activity the credit can help to maintain what remains of the production infrastructure in the Appalachian Basin and other areas, which will be needed to meet future gas needs. Competitive sources of supplies will be enhanced now and in the future because small independent producers in many regions of the country are positively effected by the credit.
3. The credit is an extremely low cost method for the government to encourage development of nonconventional fuel sources, because only *successful* efforts are rewarded.
4. Additional sources of natural gas will be made available to help achieve this country's environmental goals. Natural gas can be substituted for other fuels with significant environmental benefits.

1. Lower Gas Prices for Consumers

Retention and extension of benefits under Section 29 can greatly reduce costs for consumers of natural gas from all sources. The current so-called "bubble" in natural gas supply will likely disappear in the next 12 months, leaving gas supply and demand in rough equilibrium. (See American Gas Association, *Natural Gas Produc-*

tion Capabilities 1989-90, July 25, 1980). Given the high degree of price sensitivity for natural gas, even a small decrease in supply at the point of equilibrium can *greatly* affect the cost to consumers. The price spike for fuel oil this past December should serve as an illustration of this basic economic fact. The independent producers operating natural gas wells in the Appalachian Basin account for approximately 15 percent of the gas supply consumed in that region. What is even more important is that the proximity of this supply to the nation's largest gas consuming market is critical in meeting peak-day demand during the coldest times of the year. This supply can be increased if the credit is made permanent and is expanded to include tight sands gas. The result of maintaining Section 29 credits, therefore, could be a reduced price across all sources of natural gas production for a relatively small tax credit commitment for Section 29 gas.

The incentives proposed by the AEG will make additional supplies of gas available in the market. If the effect is only one cent per MCF reduction in the average gas price, the savings to consumers will be over $180 million dollars per year, more than enough to pay for the tax credit.

I might also point out that the benefits of lower gas prices are particularly important to low-income Americans who must spend a large portion of their salaries on the basic necessities of life like food, heat, and housing.

2. Maintenance of the Infrastructure

For 8 of the last 10 years, the Appalachian Basin lead all regions of the United States in number of natural gas completions. However, in 1988, the Appalachian Basin fell to third and in 1989 it is projected to be as low as fifth. With annual numbers of completions routinely above 10,000 in the early 1980's, the Appalachian Basin had only 3,262 completions in 1988, and we expect final numbers to show even less in 1989. (See Petroleum Information Corporation, *Petroleum Frontiers,* 1989, special supplement at 42–45).

Mr. Chairman, with the vast majority of Appalachian gas reserves found in nonconventional formations, the lagging performance of the Appalachian Basin could be offset by extension of Section 29 and reinstatement of tight sands gas. Because of the high cost involved, the Appalachian Basin has encountered great difficulty in joining any national recovery in the natural gas sector.

Most frightening is the prospect that the Appalachian Basin may be losing an entire generation of natural gas producers. As geologists, technicians and pipeline operators permanently leave the field to pursue other careers, the Appalachian Basin's capability to respond to the need for increased supplies is greatly diminished. Restoration of Section 29 credit, however, can help prevent the continued erosion of our infrastructure and insure the capacity to meet future demands, particularly in the concentrated fuel consumption area of the Northeast.

Extension of the Section 29 credit now, rather than at some future date is also particularly important to the Appalachian Basin. More than other regions of the country, the Appalachian Basin relies on outside sources of capital to fund its drilling operations. Establishing the relationships necessary to obtain this capital can take years, and the uncertainty about the future of the credit discourages potential investors from even beginning the investment evaluation process. Relief from the AMT is important to the many small companies on the Basin who routinely reinvest a large portion of their cash flow in drilling, but who do not have other profit centers generating income against which the credits can be applied.

It is critical for America's energy future to maintain the unique opportunities available in the Appalachian Basin. By virtue of its proximity to the large Northeast gas market the Appalachian Basin can most efficiently provide gas supplies necessary for the region. The Appalachian Basin has traditionally been among the most reliable and secure of domestic energy sources. The reinstatement and extension of the Section 29 credit will restore a stable energy supply in the region. Gas formations in the Appalachian region have low stabilized yield rates with levels of about 20 to 50 MCF per day per well. However, the formations are *stable,* continuing to produce for as long as 25 to 50 years. Although these wells will provide stable levels of gas even as the market fluctuates, Section 29 credits are necessary to provide an impetus for production when the return may be long-term.

3. Low Risk, Cost Effective Incentives

If Congress was offered a defense program where it only paid for systems which worked, or a housing program received funding only if decent housing was provided at an affordable cost, you would probably wonder if you were hearing correctly. But that is what this program does for natural gas. We put up the risk capital to drill and complete wells, and only if we are successful; only if gas is produced and if we earn a profit, will we earn any credit. That is the plan Congress devised in 1980 and it has been working well.

In order to be eligible for the tax credit, Section 29 requires that gas be sold prior to January 1, 2001, and produced from wells drilled prior to January 1, 1991. In addition, qualified gas must be subject to price regulation by the U.S. government. In the case of tight sands, a 1988 Supreme Court decision effectively decontrolled virtually all tight sands gas, even though prices for gas are depressed.

Mr. Chairman, tight sands gas prices have not increased with deregulation; in fact, they have fallen considerably since deregulation began in 1985. Gas prices are nowhere near the $5.17 MCF level tax officials feared *regulated* gas might reach. The anticipated windfall that the retraction of Section 29 sought to eliminate simply never materialized. Appalachian tight sands producers were hit with the double barreled blow of declining revenues and loss of the Section 29 credit.

Current prices will not support development of most nonconventional source gas. Since 1987 development of tight sands gas has virtually stopped. The same thing will happen to the other nonconventional sources if the credit is allowed to expire. This is clearly not in the best interest of the country.

4. Achieving Our Nation's Environmental Goals

Natural gas is far and away the best of the fossil fuels from an environmental perspective. Increased natural gas utilization is an efficient and economically sensible approach to achieving our clean air objectives, including the reduction of acid rain. The Gas Research Institute has found that "concern over the effects of acid rain, high levels of tropospheric ozone and the greenhouse effect" should provide "significant impetus to greater use of natural gas." (See *Science,* April 21, 1989, at 306–07). Natural gas-fired systems produce virtually no SO2, volatile organic compounds, or particulates. An exploitation of tight sands, Devonian shale, and other nonconventional gas sources is a reasonable approach towards the goals of maximizing our natural gas potential, and minimizing air pollution.

Mr. Chairman, I believe these are four good reasons for Congress to reinstate the tight sands tax credit, make the Section 29 credit permanent, and to allow use of the credit against AMT. There are other positive effects I have not addressed such as the local effects on employment and tax revenue in some of the less prosperous areas of the country.

We applaud ongoing efforts in both the House and Senate to restore the Section 29 credit for tight sands gas production and to extend the placed-in-service date and we encourage all the members of the Finance Committee to join in that effort.

Restoration and extension of the Section 29 tax credit is an essential incentive to the independent producer to assure an adequate and secure supply of natural gas for the country. Mr. Chairman, on behalf of the Appalachian Energy Group, I want to conclude by thanking you and your colleagues for bringing this matter to the attention of the public.

Statement of Arkla Exploration Company

A recent Wall Street Journal article (July 30, 1990) expressed alarm at America's "third deficit." In addition to a trade deficit and a budget deficit, there exists a growing and worrisome "infrastructure" deficit; that is to say, a lack of investment in the deteriorating physical systems behind such services as transportation, waste disposal, water resources and the delivery of energy. This deficit has contributed to serious decreases in productivity, according to a senior economist at the Chicago Federal Reserve Bank. Compare, for example, the annual productivity growth rate of the United States over the last 20 years—six-tenths of one percent (0.6%)—with that of Britain (1.8%), France (2.3%), West Germany (2.4%) or Japan (3%). Sixty percent of this slump in U.S. productivity is attributable to the so-called infrastructure deficit.

Mr. Chairman, these kinds of statistics are emblematic of this country's refusal in recent years to make long-term plans for the development and deployment of resources. We as a Nation have been on a binge of short-term self-gratification, the price of which may be our ability to provide economic leadership to the rest of the world. This myopia in the energy area, where we seem determined to yield economic decisionmaking entirely to the market, has resulted in a frightening increase in the Nation's energy dependency. That dependency has become politically palatable because of a temporary decline in energy commodity prices. But in the long run, the American consumer will pay dearly—in political as well as economic terms—for our failure in recent years to develop domestic fossil fuel resources.

I want to elaborate on what I perceive as a kind of "infrastructural" deficit that has developed in the area of petroleum production. First, I should note that the economic expansion of the 1980s occurred largely at the expense of certain regions and industries. The gas and oil producing states, like many agricultural states of the Midwest, did not share in the full measure of prosperity that was so widely publicized. In the "oil patch," the recession of 1982 has never ended. Oil and gas businesses have had to restructure, downsize, cut payrolls, promote "early outs," consolidate, and even resort to Chapter 11 just to survive. There are now only about one-fourth (1/4) the rotary rigs in action than there were in 1981. The resulting loss of experienced oil and gas people—from rig hands to geologists to engineers and managers—has placed the industry in a hole from which it could take years to climb out, even under favorable economic circumstances.

And in states like Texas, Oklahoma, Louisiana, and Arkansas, when the oil and gas business sneezes, the whole economy gets a cold. Real estate values fall. Farming and banking suffer. Unemployment rises and the tax base shrinks. In terms of non- agricultural employment during the 1980s and overall, the economies of those states exhibited a volatility nearly 44% greater than the national average. (Exhibits A–C.) The boom-and-bust rollercoaster that has become typical of the energy-based economies in those states has caused widespread hardship. The lack of a policy of stable growth and development has been equally unhealthy for producers and consumers of energy, in my estimation.

As my attached exhibits show, developments in the oil and gas business are not necessarily good ones. Reserves of natural gas—that is to say, proven supplies held ready for future delivery—reached their peak in 1970. (Exhibit D.) Notwithstanding the salutary effects of the Natural Gas Policy Act of 1978, known reserves have continued to decline overall and are now at two-thirds (2/3) the level we possessed a mere 20 years ago. For the first time since the U.S. began utilizing natural gas on a widespread basis, annual marketed production of gas has exceeded additions to reserves for nearly a generation. And the annual deficits have not been small. As we enter the 1990's, we are running a deficit of natural gas reserve additions to production of approximately 5 Tcf. (Exhibit E.)

The difference between domestic crude oil production and additions to reserves is even more disturbing. As the 1980s ended, we consumed each year approximately 1.5 billion barrels more than we found, *notwithstanding* Prudhoe Bay. (Exhibit F.) Overall, known oil reserves are declining in a virtual free fall. (Exhibits G and H.)

None of these statistics would surprise a person in the oil or gas business. The statistics, when charted, demonstrate that the history of petroleum production is the history of radical upward and downward trends in output and new discoveries. The economics of this once heavily regulated business have been erratic and unpredictable. The country nevertheless prospered because the high risks of exploration and production were matched by unparalleled exploration opportunities and high returns. Historically, this potential was sufficient to attract capital despite the fluctuations in the market.

Inevitably, the days of large domestic oil discoveries are ending. The Department of Energy foresees a change in our total oil production of *minus* 6.8 quadrillion Btu by 2010. (Exhibit I.) Instances of striking vast pools of easily produced conventional fuels are already fewer and fewer. Those kinds of reserves now exist largely in the Middle East, a region whose unreliability is demonstrated hourly on every television set in the world. While natural gas reserves are potentially more abundant than oil, domestic gas supplies produced conventionally from large reservoirs are growing at a diminishing rate: 2.9 quadrillion Btu of gas production by 2010, compared to 14.5 quadrillion Btu for coal. Meanwhile, our national appetite for cheap energy has continued to increase and that appetite is being fed increasingly by imported fuels; for example, imported crude oil is now over 50% of U.S. consumption and our annual petroleum import bill is $50 billion. It climbs to nearly $100 billion if petroleum-related imports are included. Everyone predicts that, under existing policies, that dependence (measured by oil imports as a percentage of consumption) will only grow during the next generation. (Exhibit J.)

Cheap imports not only raise our balance of payments deficit, they also exert relentless downward pressure on domestic gas and oil reserves to production ratios. Sales of gas and oil at depressed prices offers near term benefits to many sectors. Public policy favors cheap fuels. But because of current events, our inventory of available fuels is being dissipated much faster than it is being replaced by exploration and development.

In any line of business, if a merchant were to sell his low cost inventory without replenishing it, before long he would be out of business. And without his presence in the market, the remaining merchants could exact something more closely approximating monopoly prices. In light of the need to harbor oil and gas as well as financial resources, the U.S. oil and gas industry has matured. In that segment of the economy, the margins are slim, sound business judgment is at a premium, and steady public policymaking is critical. As the U.S. confronts the international energy market, it must be mindful that any lack of resolve in pursuing our national self-interest by taking maximum advantage of our own natural resources will have dire consequences.

The past several week's events in the Middle East confirm the risks inherent in oil dependency. Iraqi President Sadaam Hussein invaded Kuwait and cowed the United Arab Emirates into cutting production to support a higher OPEC price for oil. Analysts report that the cartel is once again bent on a steady rise in prices, *during an oil glut.* OPEC's previous inability to stick to its internal agreements is now changed by military coercion. While even U.S. producers stand to benefit from such increase prices, the domestic industry does not look favorably on anything that makes the consumer and the economy extremely vulnerable to price volatility or supply shortages. That vulnerability becomes greater to the extent that domestic supplies become less available and less secure. Ironically, the current ratio of domestic oil reserves to production (9:1) is the same as it was at the time of the Arab Oil Embargo.

In addition, domestic events also show the risks we run as demand and domestic reserves begin to converge. During the severe cold spell of December 1989, the deliverability of gas and oil was strained to the utmost limits both in terms of transmission capacity and availability of supply. I believe, Mr. Chairman, that we were perilously close to a widespread cessation of fuel deliveries.

I do not mean to suggest by this that the oil and gas industry faces armageddon. The resources are there. They can be made available for the long term at stable prices. Supply security can only be achieved, however, if the American public and its political leadership are willing to make the investment. Domestic oil production can continue at significant levels and at stable prices for another 40 to 50 years if the industry can afford to develop and use enhanced recovery techniques. Large domestic gas resources are recoverable under a stable pricing régime, estimates the Department of Energy. At under $3.00 per Mcf, 583 Tcf can be produced. Additionally, 174 Tcf can be recovered at between $3.00 to $5.00 per Mcf. The resources are available only to the extent the American consumer is willing to pay marginally higher prices for energy, however. I believe that the resulting stability of price and security of supply is what both producers and consumers of energy want.

How do we attain these goals? My recommendation is threefold: (1) allow for widespread exploratory drilling as a serious step toward assessing the real dimensions of our gas and oil resources; (2) impose a tax or fee on all imported fuels; and (3) continue investment tax credits for development of high-risk and high-cost energy sources.

First, it is a grave mistake to set public policy on so critical an issue based on theory and conjecture. The studies of DOE and others notwithstanding, we have only a general idea of what gas and oil reserves will be at the disposal of future generations of Americans. The person chiefly responsible at DOE for developing a national energy strategy has only recently acknowledged a high degree of uncertainty about future gas supplies. "The single biggest barrier the gas industry faces is confidence in supply, not so much for the near term, but for the long term," stated Deputy Under Secretary Linda Stuntz (quoted in *Inside FERC,* July 30, 1990). Despite such official recognition of our need for information, exploratory drilling is still limited or banned in much of the Federal domain. Despite the cries for cleaner air and clean-burning fuels, current public policy inhibits low impact exploration activities on public lands for gas reserves that would assist those environmental goals.

I foresee that energy concerns and environmentalists will come to share an interest in sensible gas exploration activities. In any event, the Congress and the public must make energy policy not on the basis of temporary market data but on the basis of a complete understanding of what resources we have available and where. Such exploratory drilling—and even subsequent domestic production of gas or oil—is relatively benign.

Second, a tax on imported fuel, particularly oil, is a rational response to a cartel that can and will manipulate energy prices to its advantage and our disadvantage. Many critics believe the benefits of such a tax would be restricted to producing states, not accounting for the contribution that such revenues could make to cleaning up the environment, helping to pay for the development of nonconventional source fuels, or retiring the national debt. In reality, the fewer tankers that must arrive at our shores with crude oil imports, the fewer are the risks of oil spills. There are nevertheless those who view an import tax as accelerating the development and exhaustion of domestic reserves. Those persons are obviously not as troubled by the nation's potential dependency on the good will of Mr. Hussein as am I. The greatest virtues of such an import fee are price stabilization and supply security. Oil imports can be taxed at a level that maintains a market price capable of rewarding domestic producers for developing and producing oil and gas reserves at a steady rate.

Finally, the Congress must continue to provide tax credits for high-risk gas production from shale, geopressurized brine, coal seams and tight formations. Relatively low market prices and high costs have diminished the revenues available from production of these reserves or have even caused losses. Development of these resources can only be ensured by the stability that derives from tax incentives. Otherwise, they will not be produced until high prices and possibly economic dislocation require them. In disregard of this eventuality, the Wellhead Decontrol Act and two orders of the Federal Energy Regulatory Commission succeeded during the past year in removing the statutory eligibility criterion for tax credits (e.g., price regulation) of tight formation gas. These tax impacts were largely unintended. The history of these measures furnishes the best conceivable example of critical energy policy being made by accident.

The first blow to the credit for tight formation gas (section 29(c)(2)(B) of the Tax Code) came one year ago with the Wellhead Decontrol Act. In addition to deregulating all gas to which no contract applied on the date of enactment, the Act shortened the availability of the credit, despite the express intention of many Senators to avoid such a result. First, the Act decontrolled regulated gas produced from wells drilled on or before the date of enactment, effective January 1, 1993. Gas produced from wells drilled after July 26, 1989 were to be deregulated on May 15, 1991. Without price regulation for tight formation gas, the credit ends under the terms of the Code. These dates therefore represent the end of tax credits for any tight formation gas from wells in these categories. Producers whose investments were predicated on the availability of credits until the year 2000 have found those expectations rendered meaningless.

The FERC then made things worse by unexpectedly holding in April 1990 that Section 121(f)(2) of the NGPA (adopted in the Wellhead Decontrol Act) could reasonably be interpreted to provide for decontrol of temporarily released gas. The Commission's theory is that the underlying contract which keeps the gas at regulated prices "ceases to apply" to the gas during the release period. This interpretation, stated in FERC Order No. 523, was a reversal of the Commission's previous interpretation on this point. In January 1990, it had held that gas released from a contract in effect on the date of enactment was *not* price deregulated unless the underlying contract was actually terminated. *Union Pacific Fuels, Inc.*, Docket No. CI89-465-000, 50 FERC Par. 61,062 (1990). In contrast, Order No. 523 states that, beginning July 26, 1989, any tight formation sold even temporarily pursuant to a release agreement is deemed price-deregulated and therefore ineligible for the credit.

Order No. 523 imposes a hardship on many gas producers. Although parties to the applicable contracts may be able to reform their agreements prospectively to avoid releases and thus the loss of the tax credit, there is no equivalent way to restore tax credits for released gas produced between July 26, 1989 and the present. Those credits are lost, unless the law is changed. For my company alone, Order No. 523 could result in nearly a $1 million loss in the first quarter of 1990.

FERC Order No. 519 is the third piece of bad news for section 29 credits. NGPA §107(c)(5) authorizes the Commission to prescribe a maximum lawful price which exceeds the otherwise applicable regulated price *if* the Commission finds that obtaining the gas involves extraordinary risks or costs. In 1980, the Commission made such a finding for tight formation gas (Order No. 99). In Order No. 519, which became effective on May 12, 1990, the Commission held that eligibility for a high incentive price (200 percent of the §103 price for new on-shore gas) was no longer Justifiable. There is one aspect of the FERC decision that is particularly objectionable. Despite requests to the contrary, the FERC expressly refused to take into account the tax impact of its decision when assessing the need for an incentive price. I must point out that most tight formation gas is not actually sold at the high incentive price level in today's competitive market. Mere eligibility for the incentive price meets the criteria of Section 29(c)(2)(B) of the Tax Code. Therefore, from my perspective, the Commission's concern about the justification for an incentive maximum lawful price is misdirected and Order No. 519 was too narrowly focused.

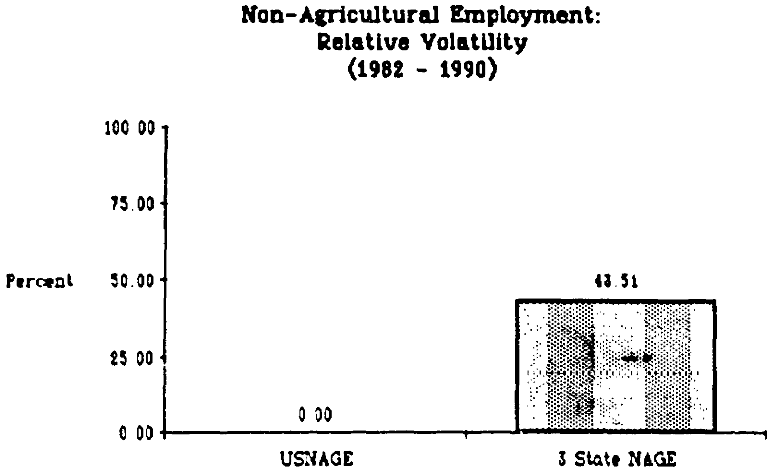
Order No. 519 means that gas produced from wells "spudded" after May 12, 1990, does not qualify for the high incentive price. Without eligibility for an incentive price, no tax credit is allowed under the current tax law. Order No. 519 will necessarily curtail tight formation drilling programs, most of which were initiated in large part in the reliance on the availability of tax credits. Until May 12, 1990, the only deadline for drilling tight formation wells had been the January 1, 1991 deadline in the Tax Code. Our company would have drilled additional wells but for Order No. 519.

This result is unfair to business people who relied on the credit when making their investment and also is unfair to Congress, which should be able to legislate regulatory policy without affecting tax policy.

These events reflect the haphazard way in which our energy policy is evolving. I therefore urge upon you more circumspect and long-range planning for the energy future of this country. That energy future need not be one of price volatility, dependency on imports, trade deficits, or supply curtailments. The industry will continue to fuel economic growth and stability and a high standard of living, *if* it has the pre-conditions that lead to dependable energy at dependable prices. But we won't have this unless Washington exerts leadership in this area. First, the country must have reliable estimates of what fuels it has at its disposal domestically as well as what its needs will be. Only continued exploration can substantiate the supply side of this equation. Second, petroleum imports that make us dependent and depress domestic prices for gas and oil must themselves be made to generate revenues that in many ways will help guarantee our security. Finally, tax credits for tight formation gas and other high-risk petroleum production represent a sound investment in future supply security and our high standard of living.

Gas and oil production is a competitive, market-sensitive, and risky business. Those resources are not simply available at the turn of a spigot. They must be planned for. And, time is growing short.

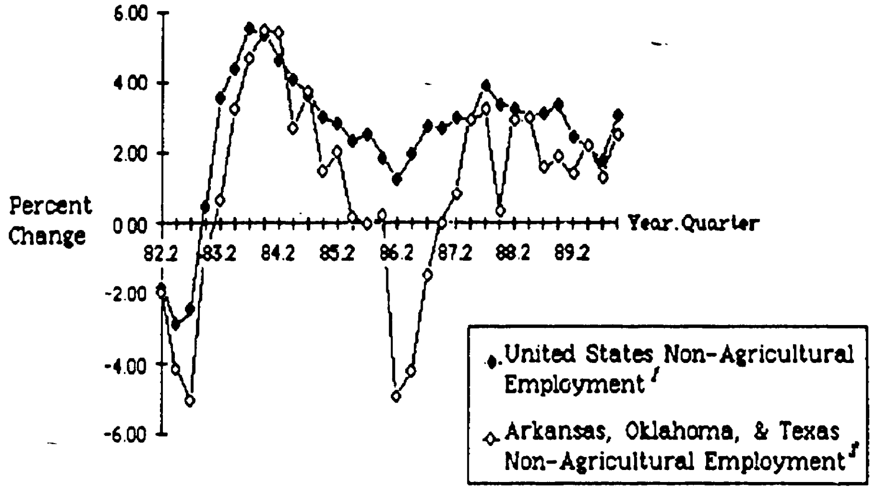
Exhibit A



USNAGE = United States Non-Agricultural Employment
3 State NAGE = Arkansas, Oklahoma, and Texas Non-Agricultural Employment

Exhibit B

Non-Agricultural Employment

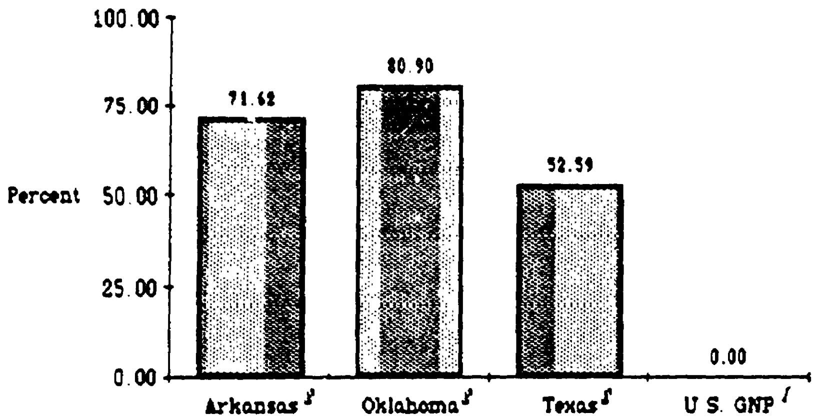


Sources:

1. *Washington University Macroeconomic Model Historical Database*
2. *Southwestern Bell Telephone, Finance & Economics District*

Exhibit C

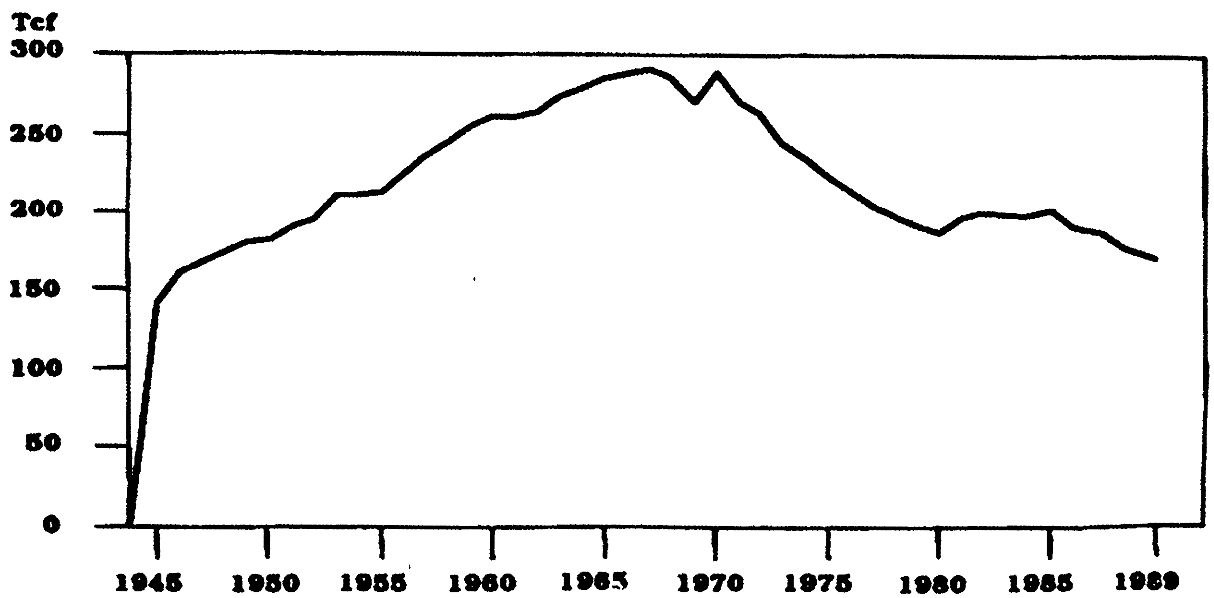
Economic Performance: Relative Volatility
(1982 -1990)



Sources
1. Washington University Macroeconometric Model Historical Database
2 Southwestern Bell Telephone, Finance & Economics District

ARKLA
EXPLORATION COMPANY

U.S. Natural Gas Reserves



Source: AGA/DOE

Exhibit D

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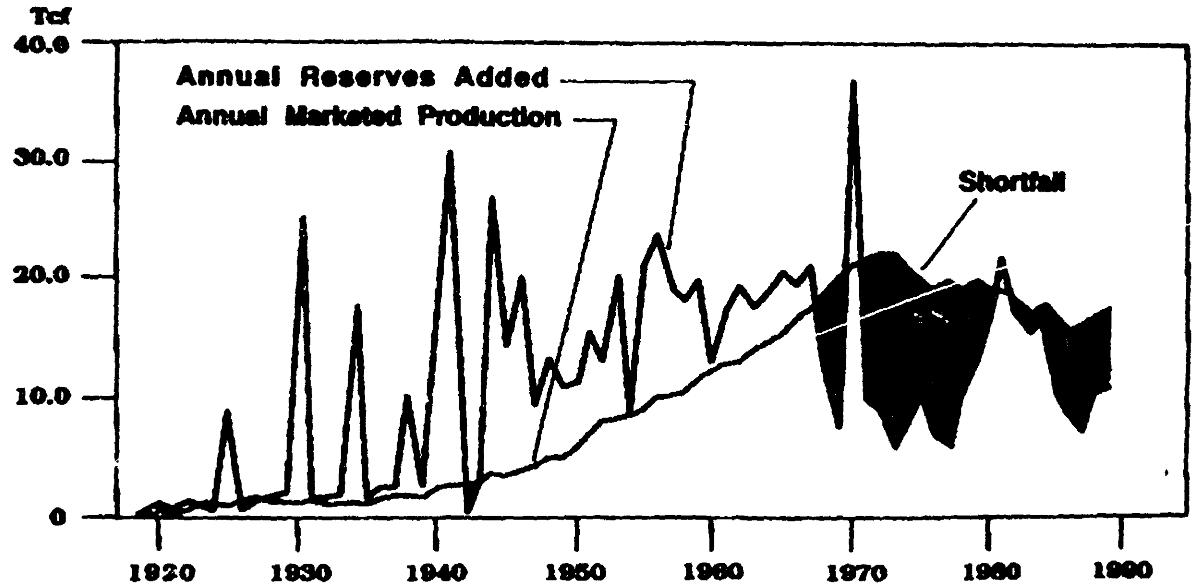
ARKLA EXPLORATION COMPANY

U.S. Natural Gas Production And Reserves

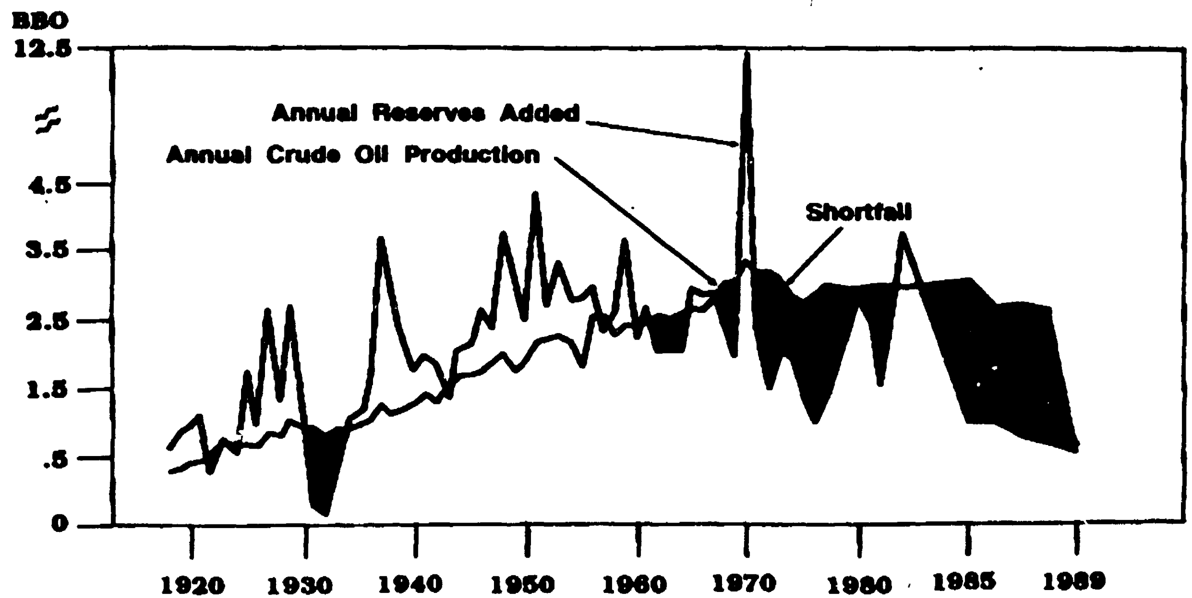


Source: AGA/DOE

Exhibit E

ARKLA
EXPLORATION COMPANY

U.S. Crude Oil Reserves And Production



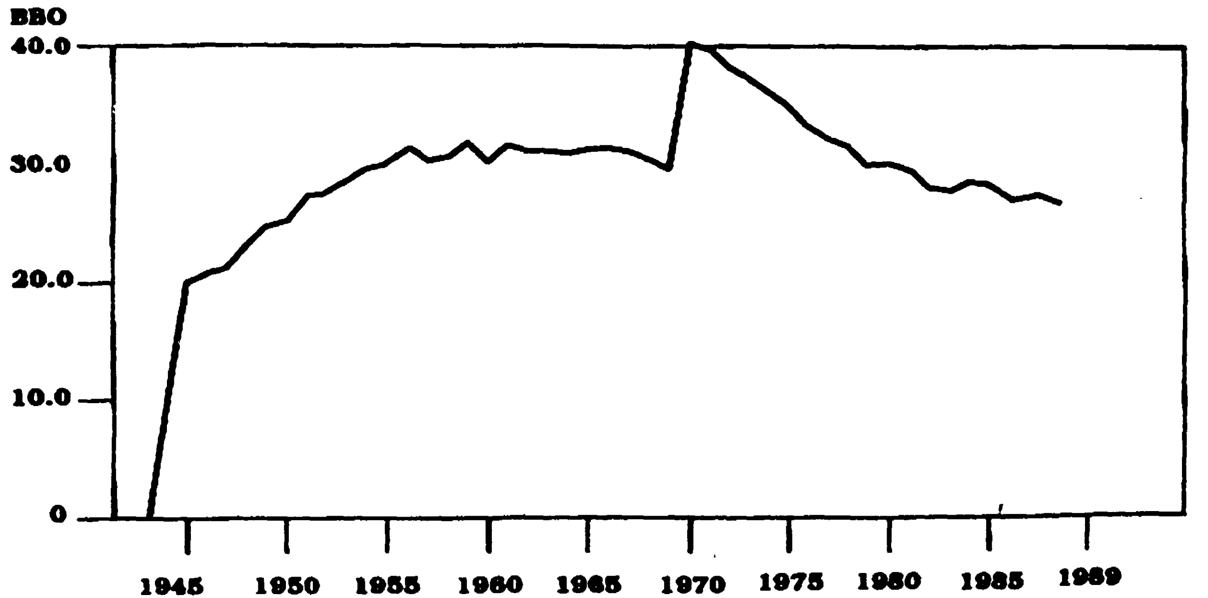
Source: API/DOE

Exhibit F

ARKLA
EXPLORATION COMPANY

U.S. Crude Oil Reserves

BILLION BARRELS OF OIL

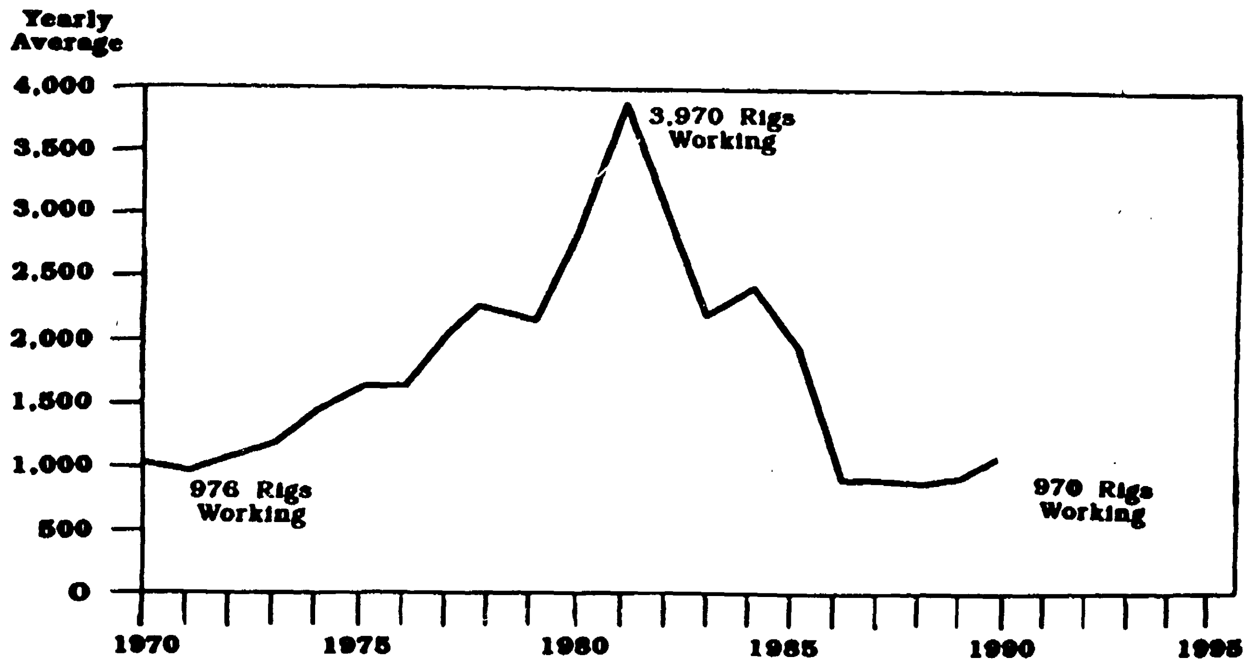


Source: API/DOE

Exhibit G

ARKLA EXPLORATION COMPANY

Rotary Rigs Active

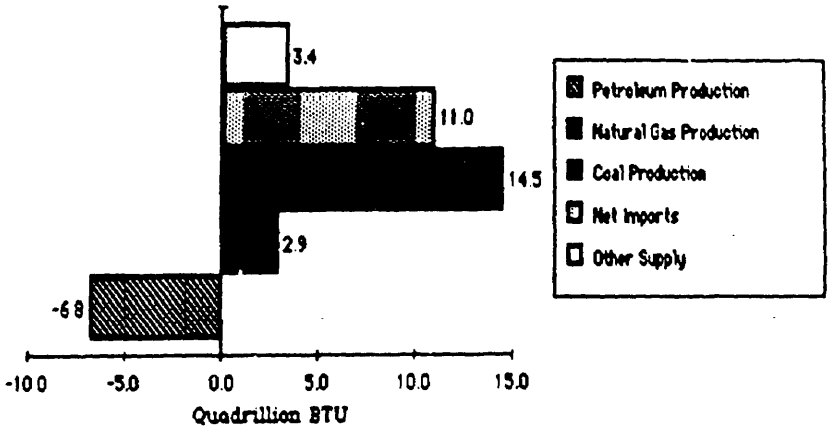


Source: Baker/Hughes Tool Co.

Exhibit H

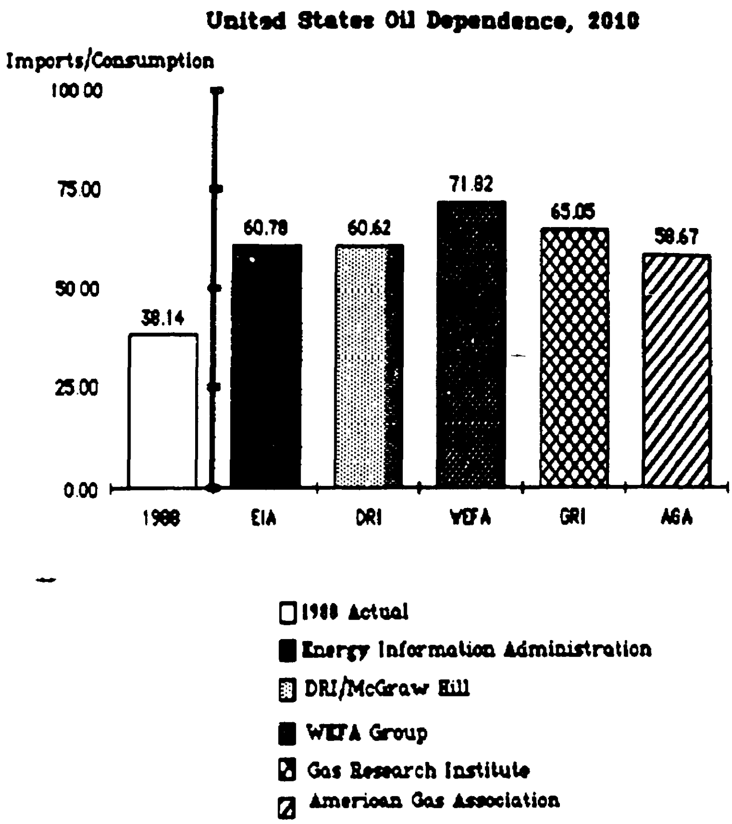
Exhibit I

Changes in Sources of Energy Base, 1988 - 2010



Source: Annual Energy Outlook 1990, Energy Information Administration, Department of Energy

Exhibit J



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STATEMENT OF CABOT OIL AND GAS CORPORATION

I. INTRODUCTION

Cabot Oil and Gas Corporation ("Cabot") is a domestic producer of oil and natural gas, whose headquarters are located in Houston, Texas. Cabot performs substantially all of its production operations in the Appalachian Basin, which is located in the Eastern United States, and the Anadarko Basin, which is located in Texas, Oklahoma, and Kansas. Cabot is one of the largest independent producers in the Appalachian Basin.

II. SUMMARY OF POSITION

Cabot believes a reinstatement of the tax credit for tight sands gas provided pursuant to Section 29 of the Internal Revenue Code of 1986 and an extension of the qualification date for credit eligibility are in the national interest due to the importance of the credit in financing projects to find and develop nonconventional fuels. Cabot therefore strongly urges that the credit be reinstated for tight sands gas and that the qualification date for credit eligibility be extended for *at least* two years. Toward that objective, Cabot strongly supports H.R. 5351, the Nonconventional Fuels Credit Extension and Modification Act of 1990, sponsored by Congressman Andrews and S. 2288, the Nonconventional Fuels Production Incentives Act of 1990, sponsored by Senator Domenici.

III. THE NONCONVENTIONAL FUELS TAX CREDIT

The Nonconventional Fuels Tax Credit applies to various qualified fuels including: oil produced from shale or tar sands, qualifying processed-wood fuels, steam produced from certain agricultural by-products, synthetic fuels produced from coal, and natural gas produced from Devonian shale, tight formations, geopressured brine, biomass, and coal seams. The credit, which amounts to $3 per barrel of oil equivalent, as adjusted for inflation with respect to those fuels other than gas from a tight formation, applies only to such qualified fuels as may be produced from a well drilled or a facility placed in service after December 31, 1979 but before January 1, 1991, and as may be sold between December 31, 1979 and January, 1, 2001. The credit for tight sands gas calculates to 52 cents per MCF.

From the perspective of the Treasury Department, the credit is extremely cost-effective because it is available solely for productive wells, and, therefore, the risk of drilling remains with the producer. Although static revenue analysis recognizes only the initial outlay for the credit in the form of foregone tax collections, a more realistic, dynamic economic analysis shows financial returns to the government in the form of additional tax receipts as the gas is introduced into the market, because the credit may be claimed only after the sale of the production giving rise to the credit.

As applied to tight sands gas, the credit was originally intended to apply only to the extent that sufficient price incentives were lacking. Specifically, the credit applies only to tight sands gas that is subject to price regulation and eligible for incentive pricing under the Natural Gas Policy Act ("NGPA") of 1978. This condition was originally included because most experts then believed that deregulation would automatically result in higher prices for natural gas. *Actually, the price of such gas has declined* since the *de facto* deregulation of most tight formation gas reserves pursuant to Federal Energy Regulatory Commission ("FERC") Order No. 99 as interpreted by the U.S. Supreme Court in the case of *F.E.R.C.* v. *Martin Exploration Co.,* 486 U.S. 204 (1988).

The credit was originally enacted by Congress in 1980 as an incentive for the exploration for and development of nonconventional fuels. Because the energy crises during the 1970's had graphically demonstrated the perils of domestic dependence on foreign energy supplies, the credit was intended to decrease costs of certain domestic production relative to imported oil and to enhance the cost competitiveness of alternative source fuels, relative to conventional ones. Because nonconventional gas production is usually subject to higher costs and lower well production rates, Congress determined that additional incentives were necessary to stimulate exploration and drilling activity with respect to such fuels.

In addition to assuring sources of domestic supply Congress may have expected that the credit would also elicit a supply response sufficient to mitigate anticipated continued price increases. In fact, according to the Department of Energy, between 1981 and 1985, the years during which tight sands production was eligible for the credit, such production increased by more than 142 percent, from 495 Bcf to 1,201 Bcf. (Department of Energy, *Drilling and Production Under Title 1 of the Natural Gas Policy Act. 1978-1986,* Jan. 1989.)

Subsequent developments suggest that another implicit objective may have been to benefit the environment by encouraging the development of alternative sources for natural gas. Natural gas, which is one of the cleanest fuels, produces far less carbon dioxide than other fossil fuels and produces no sulfur dioxide, a principal component of acid rain. Increased use of natural gas as a substitute for coal or oil will, in any event, contribute significantly to improved air quality.

Although included in Section 29 as a qualified fuel, tight sands gas has been effectively removed from eligibility for the credit due to (i) the statutory requirement that it be subject to Federal price controls, (ii) administrative action by the FERC and (iii) subsequent interpretation by the Supreme Court (*F.E.R.C.* v. *Martin Exploration Co.*). Basically, the NGPA sought to regulate prices by providing various ceiling prices for most natural gas based on its situs of production. Regarding certain geologic sources of production, however, another higher incentive price applied. Thus, certain gas was subject to dual classification, as was the case with the majority of tight sands reserves. As the phased deregulation mechanism of NGPA §121 was applied over time, a situation arose wherein gas from a particular well could be deregulated under one category, yet such gas would remain regulated under its alternative classification. In Order No. 99, the FERC ruled that gas subject to such anomalous pricing should be considered "deregulated" for pricing purposes. Subsequent litigation was finally resolved in the *Martin* case wherein the Supreme Court held in favor of the FERC regarding the issue of price regulation. As a result of the FERC Order No. 99, the *Martin* decision, and their interaction with the price regulation requirement of Section 29 as regards the eligibility of tight sands gas for the credit, most tight sands gas was disqualified from the credit. Thus, after the effective date of Order No. 99, only that tight sands gas which was committed or dedicated to interstate commerce before April 20, 1977 remained eligible for the tax credit.

Subsequent legislative and administrative actions have further reduced the universe of tight sands gas eligible for the credit. The recent enactment of the Natural Gas Wellhead Decontrol Act of 1989 has made it difficult for tight sands gas to remain eligible for the credit, by decontrolling (i) gas sold pursuant to contracts, entered into or negotiated after enactment, (ii) gas from wells drilled after enactment, and in any case, (iii) all gas by January 1, 1993. FERC Order No. 519 has also made it impossible for tight sands producers, with wells drilled or recompleted after May 12, 1990, to be eligible for the credit. Under FERC Order No. 519, the NGPA §107(c)(5) incentive price that applies to gas produced from tight formations is eliminated. Section 29(c)(2)(B)(ii) of the Code requires that in addition to being price regulated, credit eligible tight sands gas must be subject to a maximum lawful price equal to at least 150 percent of the applicable price under NGPA §103. Essentially that requirement refers to the NGPA §107 incentive price, and the elimination of that price by FERC Order 519, therefore, makes it effectively impossible for tight sands gas to meet the statutory requirements under Section 29(c)(2)(B)(ii). And, finally, in interpreting the Decontrol Act, the FERC ruled in Order No. 523 that gas which is temporarily released from the terms of a contract, is decontrolled during the period of its release.

IV. STATEMENT OF POSITION

The policies that prompted Congress to enact Section 29 persist today. Given recent geopolitical developments and the increasing tension in the Middle East as Iraq assembles its troops on the Kuwait border, our nation should be even more worried now about our dependence on unstable foreign sources of oil than in the 1970s. In addition, Americans' desires for a cleaner environment are much more pronounced today than they were ten years ago. Moreover, consumers' desires for equitably priced energy remain widespread. In order to achieve these goals, we must increase the production of the entire range of nonconventional fuels, but particularly tight sands gas, the most abundant of the nonconventional fuels enumerated in Section 29. The most direct way to encourage production of tight sands gas is to remove the various impediments to eligibility of tight sands gas for the Section 29 credit. The need for this proposal is indicated by the poor general market conditions during the last several years and the alarming increase in reliance on foreign oil. From January through May of this year, the U.S. imported approximately 45 percent of its petroleum needs, and even a sizable Strategic Petroleum Reserve is no substitute for a viable domestic production capability and supply. (Department of Energy, *Petroleum Supply Monthly*, May 1990—EIA 0109.) The tax credit would enhance the after tax price for tight sands gas and thus stimulate increased drilling for such gas.

It was estimated by the Department of Energy in a study in 1988 that over one-fifth of the gas remaining to be produced in the U.S. is found in tight sands formations. However, without benefit of the credit, gas producers will not be able to fully tap these resources until prices reach a point certain to exert great pressures on the domestic economy. If the tax credit is restored to tight sands, then it will almost certainly elicit a similar production response as it did when the applicable regulatory regime previously permitted the credit to be taken for such production.

In the same 1988 assessment, the DOE estimated that one-fourth of the remaining energy resources in the lower 48 states is found in nonconventional gas reserves. Because a large amount of our nation's proven reserves consist of these nonconventional fuels, future producers must have the benefit of the credit in order to have a sufficient economic margin with which to develop these nonconventional gas sources. In the last several years, general market conditions have been poor, contributing to the increased need for the credit. When the credit phases out for wells drilled after the end of this year, many producers will not be able to continue to develop these nonconventional gas sources.

V. ECONOMIC BENEFITS

Cabot estimates that it could economically justify drilling an additional 250 gas wells over the course of the next two years in the Appalachian Basin in the event that the gas produced therefrom were assured of credit eligibility. Most of these wells would be located in West Virginia, Pennsylvania, and New York. Not only would this activity increase the gas reserve base in states that are presently natural gas importers, but it would greatly benefit local economies. Considering that the credit may be claimed only if a well proves productive and gas produced therefrom is subsequently sold, the benefits to the states and local communities from increased state and local taxes and from local jobs created would be substantial.

VI. CONCLUSION

Cabot recommends that Congress revise and extend the Section 29 tax credit, keeping it as part of a comprehensive national energy policy. Specifically, Cabot supports the elimination of special rules for tight sands gas. History has proven the Section 29 tax credit to be a cost-effective means of stimulating production of natural gas. Now, more than ever, it is clear that our overwhelming dependence on imported oil must be reduced by increasing domestic production of natural gas. Reinstatement of the credit for tight sands gas and extension of the qualification date for all nonconventional fuels for at least two years will do just that.

STATEMENT OF THE COALITION TO AMEND SECTION TWENTY-NINE (CAST)

I. INTRODUCTION

As an ad hoc coalition of companies involved in energy production, the Coalition to Amend Section Twenty-Nine ("CAST") recognizes the critical need to develop an effective and independent national energy policy. The U.S. has long relied on foreign oil production, with oil imports approaching 50 percent of U.S. oil consumption this year. Combined with a burgeoning Federal trade deficit and environmental concerns associated with the transport and use of traditional fuels, increasing regional tensions in the Persian Gulf require that we reevaluate our national energy policy and aim to lessen our dependence on foreign oil and increase our domestic reserves of clean-burning, natural fuels.

In 1980, in an effort to make domestic energy alternatives more economically attractive in hopes of sparing the United States the industrial disruption and price fluctuation caused by the OPEC oil embargo, Congress enacted a tax credit for nonconventional fuels, which subsequently became Section 29 of the Internal Revenue Code of 1986 (the "Section 29 credit" or the "credit"). Since enactment of the Section 29 credit through 1987, the production of nonconventional fuels increased 289 percent.[1] CAST recognizes the success of the Section 29 credit in contributing to our

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[1] *Natural Gas Production in the Post-NGPA Decade,* Natural Gas Monthly, September, 1989. Noted percentage is calculated based on annual production figures for 1980 through 1987. The production figures were compiled by the Energy Information Administration of the U.S. Department of Energy for gas produced from Devonian shale, geopressured brine, coal seams, tight formations and production enhancement processes under Section 107 of the Natural Gas Policy Act.

energy security by aiding in the financing of domestic fuel production and strongly supports extension for at least two years of the credit for fuels produced from non-conventional sources, including coalbed methane and gas from Devonian shale, geopressured brine, biomass and tight sands. CAST would like to focus its testimony, however, on the importance of the credit to the continued production of coalbed methane.

II. COALBED METHANE PRODUCTION AND THE IMPORTANCE OF THE SECTION 29 CREDIT

A. Coalbed Methane Production

Coalbed methane occurs naturally as a by-product of "coalification," a process during which organic matter is chemically and thermally altered to form coal. The amount of methane produced during coalification greatly exceeds the capacity of the coal to contain it, and some of it desorbs from the coal into the surrounding rock strata and sand reservoirs. Much of the methane, however, remains in the coal seams, as the large internal surface area of a given volume of coal will enable it to hold several times more methane than a sand reservoir of the same volume. Estimates of the available U.S. coalbed methane reserves range from 72 trillion cubic feet to 860 trillion cubic feet.[2] During 1990, it is expected that one-third to one-half of all gas well completions will be coalbed methane wells and that approximately 7,000 to 9,000 coalbed methane wells will have been drilled at an investment of $3 billion.[3]

Such an investment would not be possible without the Section 29 credit, since recovering coalbed methane reserves is often a difficult and expensive operation. A typical well will find its target seam saturated with water. Before such a well will release a significant amount of gas, it must be "de-watered," a process lasting anywhere from several months to several years during which the water pressure in the coalbed is lowered by pumping until the coal finally releases free gas. In addition to the expenses associated with de-watering and proper disposal of the resulting waste water, many of the wells require expensive "fracing," or the fracturing of coal seams to stimulate production. The producer may also need compressors to deliver the gas to a pipeline, since many wells release methane at a less than marketable pressure. Most of this equipment is not required in conventional gas production. Its use in coal methane development results in an initial investment requirement for the average coalbed well that is significantly higher than that of the average conventional gas well of comparable depth.

B. Mechanics of the Section 29 Credit

1. Qualification

Section 29 is applicable to domestic production of various qualified fuels, including: (i) oil produced from shale or tar sands, (ii) qualifying processed-wood fuels, (iii) steam produced from certain agricultural by-products, (iv) synthetic fuels produced from coals (including lignite), and (v) natural gas produced from Devonian shale, tight formations, geopressured brine, biomass and coal seams.

Section 29(f) provides that the credit applies with respect to such qualified fuels which are produced from a well drilled or facility placed in service after December 31, 1979 and before January 1, 1991 and which are sold after December 31, 1979 and before January 1, 2001. Congress limited the credit's application to gas as is sold in an effort to assure the credit's cost effectiveness by making sure the risks associated with development would remain with the producer. Furthermore, the application of the credit is limited in the area of natural gas by Section 29(e), to such gas as is sold without regard to the incentive pricing provisions of Section 107 of the Natural Gas Policy Act of 1978 ("NGPA") and Subtitle B of Title I thereof.

Although gas produced from coal seams was an unregulated category of gas at the time of the credit's enactment, and therefore was not subject to the pricing provisions of the NGPA, one feature of that statute remains relevant to the determination of the credit eligibility of all natural gas other than that which is synthetically derived. NGPA Section 503 establishes a procedure for the determination of gas producing formations. Basically, NGPA Section 503 allocates primary responsibility for

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[2] *Status of Coalbed Methane Recovery in the United States,* Natural Gas Monthly, September, 1988.

[3] *Economics and Financing of Coalbed Methane Ventures,* Ammonite Resources, January, 1990. The Exhibits appended hereto are taken from the study conducted by Ammonite Resources, a firm of consulting geologists and engineers headquartered in New Canaan, Connecticut, which has considerable experience in energy production. To the extent applicable, the attached Exhibits remain subject to copyright.

well determinations to the States but subjects such State decisions to review by the Federal Energy Regulatory Commission ("FERC"). In the event the FERC fails to find preliminarily that the determination of a State jurisdictional agency is unsupported by substantial evidence within forty-five days of its notice thereof, and unless such finding is finalized within one hundred and twenty days of the preliminary decision, the well determination is irreversible. (NGPA Section 503 is slated for repeal on January 1, 1993, pursuant to the Natural Gas Wellhead Decontrol Act of 1989 ("Decontrol Act").)

2. Computation.

The computation of the credit is a complex matter which is a function of the barrel of oil equivalent of the qualified fuel in question, the rate of inflation, and the price of oil. Algebraically, this computation may be expressed as follows:

Available Credit = \$3/BOE x I x (PH);

(i) BOE equals the barrel of oil equivalent (5.8 MMBtu in the case of natural gas);

(ii) I equals the inflation adjustment factor, determined annually by the Department of Energy, and the Internal Revenue Service; and

(iii) PH equals a phaseout factor which may also be algebraically determined but, in any event, always is less than or equal to 1, depending on the price of domestic crude oil.

The oil price decline of the 1980s brought the credit into full flower. When oil prices were high prior to 1981, the credit was effectively phased out. Beginning in 1981, however, the phaseout factor was only partially operative, and producers were able to net approximately \$.25/MMBtu. This amount increased to approximately \$.66/MMBtu in 1982, as oil prices experienced their steepest decline of the decade and as the effect of the phaseout factor was consequently eradicated. Since that time, due to modest but consistent inflation adjustments and to the fact that the phaseout factor remains ineffective, the increase in the credit has occurred more slowly, albeit steadily. The value of the credit in 1986 was approximately \$.75/MMBtu, increasing to \$.78/MMBtu in 1987 and \$.81/MMBtu in 1988. Current projections, based on expectations that crude oil prices will remain stable, that the credit remains in effect in spite of its scheduled expiration, and that GNP price deflation forecasts are accurate, indicate a credit value of \$.91/MMBtu in 1990, increasing steadily to as much as \$1.34/MMBtu in the year 2000.

These consistent annual increases in the value of the credit particularly highlight the effect of the inflation adjustment provision and its interaction with the phaseout factor. The dynamics between these two elements of the credit's computation and their respective relationships to the depressed state of recent world oil prices, relative to those in effect in 1980, have lately operated to make the credit a crucial variable in the investment analysis applied to qualified fuel development projects.

3. Limitations and Adjustments

In addition to the inflation adjustment and phaseout provisions, the statute provides several other limitations and adjustments to the credit, most of which are found at Section 29(b). For example, Section 29(b)(4) requires that the amount of the credit must be reduced by creditable amounts allowed pursuant to the general business energy credit of Section 38, as adjusted by applicable recapture rules. Similarly, Section 29(b)(3) reduced the credit proportionately to reflect amounts made available to a particular project by way of public financial grants, tax exempt bond proceeds or subsidized energy financings as described at Section 48. In each instance, these limitations are imposed as a result of Congress' determination that the principal purposes of the credit, to provide incentives for marginal projects and to support prices of qualified fuels, are adequately assured by other means.

Congress also provided a phaseout mechanism which would serve necessarily to limit creditable amounts to the extent that energy commodity price increases outstrip inflation. The phaseout is determined pursuant to a calculation that fluctuates in accordance with oil prices so that as oil prices fall, phaseout amounts decline. Thus, the phaseout would never serve necessarily to permanently reduce or terminate the credit.

C. The Importance of the Section 29 Credit

The enactment of the Section 29 credit transformed coalbed methane, once viewed only as a hazard to coal miners, into a valuable economic resource. To illustrate the effects that the Section 29 credit has on the production of coalbed methane, it is useful to compare several economic indicators, including the internal rate of return (the rate of discount at which net present value is equal to zero), the profit to investment ratio and the years until pay out (how long it takes to recoup the investment), as calculated both with and without the Section 29 credit. Exhibit 2, an economic model developed as part of an extensive study of the economics and financing of coalbed methane ventures, compares the internal rate of return (the "IRR"), the profit to investment ratio (the "P/I") and the years to payout ("Yrs. to P.O.") of eight of the thirteen major coalbed basins, including the San Juan Basin in Colorado and New Mexico and the Black Warrior Basin in Alabama, the two basins where the most active drilling occurs, the Northern and Central Appalachian Basins, the Raton and Piceance Basins in Colorado, the Powder River Basin in Wyoming and the Western Washington State Basin.

Comparison of after tax figures indicates that coalbed methane production in the San Juan Basin provides substantial economic returns with or without the Section 29 credit. This scenario, however, is unique to the San Juan Basin, particularly to its geologically favorable areas, which are limited and are already largely developed by major producers who are able to take advantage of economies of scale.

When comparing the after tax figures for other basins, the economic conditions become less favorable and signify the need for higher wellhead gas prices or production incentives such as the Section 29 credit. For example, the economic figures for an average Black Warrior Basin well (200 mcf/d with a decline rate of 15 percent) point out the necessity of the Section 29 credit. Without the credit, the after tax IRR is 13 percent, the P/I is 0.6 and the pay out period is 5.0 years. On an after tax basis with the Section 29 credit, the IRR increases to an acceptable 34 percent, the P/I is more than doubled to 1.9 and the pay out is reduced to 3.0 years. Exhibits 3 and 4 provide more detailed information on the economic conditions surrounding such a well. It is anticipated that as many as 4,500 wells will be drilled in the Black Warrior Basin at a cost of $1 billion by the end of this year as a direct result of the Section 29 economic incentive.[4] The Black Warrior models illustrate that without the availability of the Section 29 credit, investors would be unlikely to invest in most coalbed methane production opportunities and would seek more favorable returns elsewhere.

III. EXTENSION OF THE SECTION 29 CREDIT

A. Congressional Intent

In enacting the tax credit for the production of nonconventional fuels, Congress intended to "provide producers of alternative fuels with protection against significant decreases in the average wellhead price for the uncontrolled domestic oil, with which alternative fuels frequently compete." [5] By decreasing the costs associated with the production of nonconventional fuels, Congress believed the tax credit would encourage the development of such resources.[6] The supply response of producers of qualified fuels suggests that the domestic production related aspects of congressional intent were well served in the case of Section 29.

Other objectives intended by Congress in enacting the credit, however, although partially attained, remain unsatisfied. Recognizing that nonconventional fuels production would involve new technologies, Congress thought the tax credit would be necessary until production technologies reached the stage at which nonconventional fuels production could compete with conventional fuels.[7] Since its enactment in 1980, the availability of the credit has spurred interest in coalbed methane production technology and has resulted in the development of extraction techniques capable of increasing methane recovery at a lower unit cost of production. However, the advancing technologies have yet to be refined to the point at which the market value of the recovered methane from an average coalbed well exceeds the costs of its production without the use of the Section 29 credit. Total reliance on market forces to provide sufficient incentives for continued development of coal methane production technology and the natural gas content of coal reserves will result in a deferral of further progress until gas prices rise to a level certain to cause significant economic dislocation.

Extension of the credit would provide the bridge by which such supply disruption and consequent economic hardship may be traversed, and in a manner which is demonstrably cost effective to the government. The expiration of the qualification

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[4] *Id.*

[5] H.R. CONF. REP. No. 817, 96th Cong., 2d Sess. 139, reprinted in 1980 U.S. CODE CONG. & ADMIN. NEWS 642, 691.

[6] S. REP. No. 394, 96th Cong., 1st Sess. 87, reprinted in 1980 U.S. CODE CONG. & ADMIN. NEWS 410, 496.

[7] *Id.*

period for the credit, however, would eliminate any further incentive to improve coalbed methane production technologies, resulting in a virtual cessation of production in most areas and the loss of thousands of cubic feet of potential energy reserves, clearly failing to carry out the original intent of Congress in enacting the Section 29 credit.

B. Recent Developments

During the drafting last year of fiscal year 1990 omnibus budget reconciliation legislation, the Senate Committee on Finance recommended for inclusion in the budget package a proposal to extend for two years the qualifying period for the nonconventional fuels tax credit provided by Section 29. Although the Senate proposal was not included in the final budget legislation, CAST is hopeful that the landmark budget negotiations currently underway between Congress and the Administration will provide the venue for a reevaluation of our national energy needs to include an extension of the Section 29 credit. Several legislative proposals to modify or extend the credit have been introduced during the current Congress. Senator Pete Domenici (R-NM) introduced one such measure, S. 2288, the Nonconventional Fuels Production Incentives Act of 1990, in March of this year. S. 2288 would extend until January 1, 1993 the qualifying period for the credit. In the House of Representatives, Congressman Michael Andrews (D-TX) recently introduced comparable legislation, the Nonconventional Fuels Credit Extension and Modification Act of 1990, H.R. 5351. CAST strongly supports the extension provisions of both S. 2288 and H.R. 5351 and urges the enactment of such legislation this year.

IV. CONCLUSION

CAST understands the limits under which Congress must act in considering such legislation in the current climate of budgetary restraint. However, at a time of reported record breaking U.S. oil imports and escalating regional conflicts in the Middle East and Persian Gulf, CAST believes we must act immediately to lessen our dependence on imported energy. Increasing production of domestic energy resources through the extension of the Section 29 credit is a cost-effective investment in our future energy security.

PROJECTED COALBED METHANE ACTIVITY THROUGH 1990

Basin	# Operators	Projected Wells			Investment $MM			Peak Production MMCF/D (Anticipated by 1992)		
San Juan	27	2,482	—	2,787	1,500	—	1,650	1,250	—	1,406
Black Warrior	23	3,730	—	4,448	1,000	—	1,225	769	—	917
Appalachian	8	70	—	365	16	—	84	11	—	58
Raton	6	85	—	419	36	—	180	30	—	146
Piceance	8	75	—	100	37	—	50	26	—	35
Powder River	20	100	—	300	10	—	30	25	—	75
Greater Green River	13	190	—	444	95	—	222	92	—	192
Wind River	—		—			—			—	
Uinta	3	5	—		3	—			—	
Western Washington	3	60	—	100	21	—	35	21	—	35
S.E. Kansas	3	48	—	58	1	—	2	5	—	6
Total:		6,845	—	9,026	2,719	—	3,481	2,229	—	2,870

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EXHIBIT 1

AMMONITE RESOURCES 5/90

COALBED METHANE ECONOMIC MODELS
BASIN COMPARISONS

BASIN	BEFORE TAX % IRR	BEFORE TAX PI	BEFORE TAX Yrs. to P.O.	AFTER TAX Without Sec. 29 Credit % IRR	AFTER TAX Without Sec. 29 Credit PI	AFTER TAX Without Sec. 29 Credit Yrs. to P.O.	AFTER TAX With Sec. 29 Credit % IRR	AFTER TAX With Sec. 29 Credit PI	AFTER TAX With Sec. 29 Credit Yrs. to P.O.
SAN JUAN									
"Sweet Spot" @ 6 8%	73	21 4	2 4	57	14 1	2 7	90	20 7	1 9
"Sweet Spot" @ 15%	70	10 5	2 4	55	7 0	2 7	88	12 3	1 9
750 mcf @ 10%	37	7 0	3 6	30	4 7	4 1	53	7 7	2 8
750 mcf @ 15%	36	4 6	3 6	29	3 1	4 1	52	5 9	2 8
750 mcf @ 15% — (Promoted)	27	2 9	4 0	22	1 9	4 5	43	3 9	3 0
500 mcf @ 9%	28	5 4	4 7	23	3 6	5 3	39	5 9	3 8
350 mcf @ 8%	21	6 5	5 9	17	3 6	6 7	30	5 4	4 3
"Fringe" 200 mcf @ 15%	42	4 7	3 3	35	3 1	3 7	60	7 2	2 4
RATON									
400 mcf @ 8%	34	5 4	3 6	28	3 8	4 0	58	6 8	2 3
280 mcf @ 7%	15	2 1	6 3	13	1 4	6 9	31	3 0	3 6
PICEANCE									
1 mmcf @ 10%	44	6 6	2 9	36	4 4	3 2	74	8 2	2 0
POWDER RIVER									
East; 100 mcf @ 30%	51	2 1	2 1	38	1 4	2 6	100+	5 0	1 3
Central; 200 mcf @ 28%	43	4 3	3 1	36	2 8	3 4	75	7.5	2 3
GREEN RIVER									
WESTERN WASHINGTON									
800 mcf @ 10%	30	5 3	4 3	25	3 5	4 6	45	6 2	3 3
Southeast Kansas									
85 mcf @ 28%	73	3 8	1 8	57	2 5	2 0	100+	6 5	1 4
NORTHERN APPALACHIAN									
160 mcf @ 20%	23	1 4	3 8	18	0 9	4 2	36	2 0	3 0
Promoted	15	0 8	4 3	12	0 5	4 7	28	1 4	3 2
CENTRAL APPALACHIAN									
200 mcf @ 18%	36	2 9	3 2	29	1 9	3 5	40	3 5	2 8
BLACK WARRIOR									
280 mcf @ 6.8%	33	4 4	3 4	28	2 8	3 7	50	4 9	2 5
280 mcf @ 15%	31	2 4	3 4	26	1 6	3 8	50	3 3	2 4
Promoted	23	1 4	3 8	18	1 0	4 3	40	2 2	2 7
200 mcf @ 15%	17	1 0	4 6	13	0 6	5 0	34	1 8	3 0
Promoted	10	0 5	5 4	8 5	0 4	5 8	28	1 3	3 3

EXHIBIT 2

[illegible] RESOURCES 5/89

COALBED METHANE ECONOMIC MODEL

BASIN Black Warrior MODEL 3200 Ft "Average" Well (15% Decline Case)
80 Acre Unit

Years	Gross Gas Production MMCF/Yr	Net Gas Production MMCF/Yr	Gas Price $/MCF	Net Revenue $000/Yr	L O E $000/Yr	Production Taxes $000/Yr	Investment $000/Yr	Net Cash Before Tax $000/Yr	Income Tax @ 34% $000/Yr	Section 29 Credit $000/Yr	Net Cash After Tax $000/Yr
1990	18	15	1.95	28	14	1	325	312	63	13	235
1991	70	57	2.05	116	28	5		84	22	53	114
1992	72	58	2.15	125	28	5		92	25	56	123
1993	62	50	2.26	114	23	5		86	24	51	113
1994	53	43	2.37	102	18	4		80	23	45	102
1995	45	36	2.49	91	19	5		66	19	40	87
1996	38	31	2.61	81	20	6		55	15	35	74
1997	32	26	2.74	72	21	6		46	13	31	64
1998	28	22	2.88	65	22	5		38	10	27	55
1999	23	19	3.03	58	23	5		30	8	24	46
2000	20	16	3.18	51	24	4		23	6	21	38
2001	17	14	3.34	46	25	4		17	4	0	13
2002	14	12	3.50	41	27	3		11	3	0	9
2003	12	10	3.50	35	28	3		4	0	0	4
2004	10	8	3.50	30	29	2		2	2	0	0
Totals	515	418		1055	349	63		318	108	397	607

MODEL PARAMETERS

Production Decline, %/Yr	15
Net Revenue Interest	0.8125
Cost & Price Escalation, %/Yr	5
Maximum Gas Price, $/MCF	3.50

Before Tax Cash Flow
Net Pr. Value @ 12% - 54
Int Rate Of Rtrn, % - 17
Profit/Invest Ratio - 1.0

After Tax Cash Flow
Net Pr Value @ 12% - 251
Int Rate Of Rtrn, % - 34
Profit/Invest Ratio - 1.9

AMMONITE RESOURCES, 1/90

EXHIBIT 3

COALBED METHANE ECONOMIC MODEL

AMMONITE RESOURCES

INCOME TAX CALCULATIONS

BASIN: Black Warrior

MODEL: 3200 Ft "Average" Well (15% Decline Rate Case)
80 Acre Unit

Years	Investments: Leasehold $000/Yr.	Investments: Tangibles $000/Yr	Intangibles $000/Yr	Net Gas Production MMCF/Yr.	Net Revenue $000/Yr	Operating Cost & Taxes $000/Yr.	Deprec'n & Deplet'n $000/Yr	Taxable Income $000/Yr	Income Tax @ 34% $000/Yr.
1990	10	120	195	15	28	15	6	-186	-63
1991	0	0	0	57	116	33	18	66	22
1992	0	0	0	58	125	33	18	74	25
1993	0	0	0	50	114	28	16	71	24
1994	0	0	0	43	102	22	13	66	23
1995	0	0	0	36	91	24	11	56	19
1996	0	0	0	31	81	26	10	45	15
1997	0	0	0	26	72	27	8	38	13
1998	0	0	0	22	65	27	7	31	10
1999	0	0	0	19	58	28	6	24	8
2000	0	0	0	16	51	28	5	18	6
2001	0	0	0	14	46	29	4	13	4
2002	0	0	0	12	41	30	4	7	3
2003	0	0	0	10	35	31	3	1	0
2004	0	0	0	8	30	32	3	-5	-2
Totals	10	120	195	418	1055	412	130	318	108

EXHIBIT 4

BEST AVAILABLE COPY

STATEMENT OF R. LACY, INC.

R. Lacy, Inc. is pleased to present its comments to the Subcommittee on Energy and Agriculture, Committee on Finance in response to a request for written testimony relating to the hearing held July 27, 1990. R. Lacy, Inc.'s comments focus on the need for a proposed modification of Internal Revenue Code Section 29, the credit for producing fuel from a nonconventional source, as it applies to tight formation gas.

INTRODUCTION

R. Lacy, Inc. is a producer of tight formation gas in East Texas from acreage which was dedicated to interstate commerce prior to April 20, 1977, pursuant to the Natural Gas Policy Act of 1978 ("NGPA"). This dedicated gas was not deregulated in 1985, along with other types of tight formation gas. As explained more fully below, this gas, because it was produced from wells drilled on or before May 12, 1990, now qualifies for the Section 29 credit only until the gas is deregulated under the Natural Gas wellhead Decontrol Act of 1989 ("Decontrol Act"). Prior to the passage of the Decontrol Act, R. Lacy, Inc.'s and other company's production from this type of well would have been eligible for the credit until January 1, 2001, as provided in the tax code. Additionally, as also explained below, a recent Federal Regulatory Energy Administration ("FERC") order has foreshortened this eligibility for certain "released" gas from these wells.

R. Lacy, Inc. also owns lease rights allowing the company to drill several new tight formation gas wells. However, the risks inherent to drilling these expensive wells has been seriously increased by the loss of Section 29 credits through the effects of the Decontrol Act and recent decisions by the FERC. Further drilling has also been forestalled by the expiration of the Section 29 credit for wells drilled after 1990.

IMPORTANCE OF THE CREDIT FOR TIGHT FORMATION GAS

Testimony presented at the July hearing by Enron highlights a 1988 Department of Energy study which determined that tight gas reserves comprise approximately 180 trillion cubic feet or one-fifth of estimated U.S. reserves of natural gas. The need to produce from these vast gas reserves is particularly pertinent in light of recent developments in the Middle East. The unsettled situation there dramatically emphasizes the urgency for the U.S. to develop and produce gas from alternative fuel sources.

The Section 29 credit was originally designed to address these needs. In approving the credit, Congress acknowledged that realistically, the market climate cannot support the large investment and risks involved in the production of gas from a tight formation. In comparison, with the Section 29 credit, the likelihood of an acceptable rate of return for a producer substantially increases.

This conclusion is supported by data included in the attached study which analyzes the economic benefits of the Section 29 credit. The study was compiled by the energy consulting firm of La Rue, Moore & Schafer, Inc. and is based on actual, rather than hypothetical, data from R. Lacy, Inc.'s experience in developing tight formation property in the Carthage Field of East Texas. Because the study is based on an actual producer's experience, the analysts were "able to view development of a tight gas property through the eyes of a prudent operator as he assessed his risk."

In discussing the risk factors, the study specifically concluded that:

> If a 10 percent pretax rate of return is selected as the minimum acceptable for risk ventures, the chance of failure in a group of five test wells is 31.5 percent, without the tight gas credit. With the tight gas credit, the chance of failure drops to 10 percent. [*See* accompanying cover letter, Result 5]

Accordingly, the study shows that under current market conditions, the credit is necessary to adequately remove the high risks involved with tight formation gas production.

In contrast, the Department of Treasury has argued, in its written testimony submitted for this hearing, that because virtually all tight formation gas is now deregulated (for reasons discussed below) the Department does not support modifying the Section 29 credit to include this gas. Their argument incorrectly ignores the additional fact that, under current market conditions where drilling these wells involves high risks, the underlying purpose of the credit is better served without the regulatory requirement.

As the Carthage study and as testimony given by other witnesses at this hearing have indicated, tight formation gas will not be developed without the credit, because the current price for natural gas is too low. Treasury's testimony concedes that when Congress included the regulation requirement under Section 29 for tight formation gas, the drafters were working under an erroneous assumption that the regulated price for natural gas would be below the market price existing in an unregulated market. The testimony, however, ignores the logical results from this erroneous assumption. In reality, because the market price has been well below the regulated price, deregulation has discouraged additional tight formation gas production. The market has necessitated the passage of an amendment to remove the regulatory requirement from the credit.

SUMMARY OF WHY TIGHT FORMATION GAS IS NO LONGER ELIGIBLE FOR THE CREDIT

Tight formation gas is no longer eligible for the Section 29 credit because of the unintended effects resulting from the passage of non-tax related Congressional legislation, the Decontrol Act, as well as the release of recent FERC decisions. The following paragraphs explain this interaction.

The Section 29 credit was approved two years after passage of the NGPA. Because of assumptions made at the time, Congress limited the availability of the Section 29 credit to producers of tight formation gas which was regulated and eligible for incentive prices under the NGPA. The NGPA deregulated some, but not all, natural gas from tight formations. Specifically, all gas which was produced from property dedicated or committed to interstate commerce by April 20, 1977, remained regulated.

Unfortunately, later actions, including Congress passing the Decontrol Act and FERC releasing decisions relating to tight formation gas, have exacerbated problems created by the regulatory and incentive price restrictions in the tax code. As explained in the following paragraphs, these problems can only be resolved by modifying Section 29.[1]

PROBLEMS CREATED BY THE DECONTROL ACT

With passage of the Decontrol Act, all regulated gas (including tight formation) will be decontrolled by January 1, 1993. Accordingly, by 1993, tight formation gas which otherwise was not deregulated by the NGPA, will no longer qualify for the credit under the current definition of the term "gas produced from a tight formation" contained in Section 29. The effect is to reduce the time period an otherwise qualified well would be eligible for the credit by eight or more years. Under current tax law, gas from regulated wells otherwise would have qualified for the credit if the gas was sold before January 1, 2001.

Another impediment to further production is the distinction made in the Decontrol Act between wells drilled before and after the date of enactment, July 26, 1989. Under a special effective date rule, gas produced from a well drilled after July 26, 1989 is deregulated on May 15, 1991. Therefore, gas from those wells, which otherwise would have generated credits through the year 2000, will now lose eligibility for the credit as early as May 15, 1991.

Accordingly, the Decontrol Act produces results affecting the Section 29 credit which clearly are contrary to the original intent of Congress. Even if, in 1980, Congress believed that this gas would eventually be deregulated, they could not have known that regulated gas prices would eventually become higher than deregulated prices. Deregulation provides no incentive to produce this gas. Without a conforming tax amendment, the Decontrol Act, as enacted, is a strong disincentive to additional drilling. Significantly, the legislative history of the Decontrol Act specifically states that "[i]n no way are the [Senate Energy and Natural Resources] Committee's actions [approving the Decontrol Act] intended to impair the continued viability of the tax credit for production of fuels from non-conventional sources." Statement of Senator Wallop, S. Rept. No. 101-38 to the Decontrol Act (May 31, 1989).

PROBLEMS CREATED BY RECENT FERC DECISIONS

Consistent with the problems created last year by the Decontrol Act, the FERC has issued two recent decisions which dramatically limit the ability of a tight formation gas producer to use the Section 29 credit.

In the first decision, Order No. 519, the FERC impacted the qualification of tight formation gas for incentive prices. As mentioned above, in addition to being regulat-

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[1] Moreover, because this credit has enhanced the likelihood that otherwise unrecoverable gas resources are recovered, R. Lacy, Inc. also urges Congress to extend the current application date relating to wells drilled before January 1, 1991, for at least two years.

ed, Section 29 also requires tight formation gas to be eligible for incentive prices.[2] Under the regulatory scheme provided under Section 107(c)(5) of the NGPA, FERC is authorized to prescribe an incentive price for particular types of gas, if the FERC finds that obtaining the gas involves extraordinary risks or costs. This price can be set at a level which exceeds the otherwise applicable regulated price for such gas. In 1980, the FERC made such a finding for tight formation gas (Order No. 99).

In Order No. 519, which became effective for wells "spudded" after May 12, 1990, the FERC held that the high incentive price (200 percent of the section 103 price for new on-shore gas) was no longer justifiable at the time for tight formation gas. Therefore, tight formation gas produced from wells "spudded" after May 12, 1990, does not qualify for the high incentive price and, therefore, the credit.[3]

The effect of Order No. 519 is to curtail tight formation drilling programs which were initiated largely in reliance on the availability of tax credits to the maximum extent permitted by the tax code and the Decontrol Act. Until May 12, 1990, the only deadline for drilling tight formation wells was the January 1, 1991 deadline established in the tax code.

Finally, in Order No. 523, which clearly illustrates FERC's affirmative policy of ignoring the tax consequences of their decisions, the FERC deregulated gas released temporarily from a contract for sale in effect on the date of enactment of the Decontrol Act, July 26, 1989. However, the FERC's treatment of released gas also recognized that, if such gas is subsequently sold under the original contract, it once again becomes price-regulated. Because the FERC is not concerned with the tax consequences of their decision, this Order has the effect of rendering ineligible for the Section 29 credit any tight formation gas which is released from a pre-enactment contract, retroactively and prospectively. Although parties to the applicable contracts may reform their agreements prospectively to avoid loss of the regulated price or tax credit, there is no equivalent way of restoring tax credits for released gas produced between July, 26, 1989 and the present.

DISCUSSION OF PENDING LEGISLATION

A number of bills relating to the Section 29 credit and tight formation gas have been introduced in both the House and the Senate. R. Lacy, Inc. would like to emphasize its support of two particularly effective pieces of legislation.

S. 2288, introduced by Senator Pete Dominici (R-NM), goes a long way in addressing the problems created by the regulatory requirement in Section 29(c)(2)(B), and R. Lacy, Inc. supports this legislation.

H.R. 5351, introduced by Representative Michael Andrews (D-TX), also resolves the problems created by the regulatory requirement, and R. Lacy, Inc. urges the Committee to review this approach to tight formation gas qualification. Rep. Andrews' bill is drafted differently in light of the subsequent release of FERC Order No. 523 relating to released gas, an issue not covered by S. 2288.

CONCLUSION

The requirement that tight formation gas be regulated in order to qualify for the Section 29 credit has inadvertently reduced an opportunity Congress has to encourage increased nonconventional fuels exploration and development. It is ironic and fortunate that Congress must consider extending and modifying the Section 29 credit at a time when the need for nonconventional fuels is more apparent than it has been since the credit was originally enacted.

When the Section 29 credit was enacted in 1980, Congress believed that the regulatory requirement for tight formation gas was necessary because most experts at the time indicated that deregulation meant increasingly higher prices for natural gas. Such price increases would have necessarily obviated the need for a production tax incentive. In fact, however, gas prices have declined in real terms since then. Consequently, continuation and expansion of the credit is more critical now than ever before.

Last year, the Finance Committee recognized the importance of extending the Section 29 credit and modifying it to include deregulated tight formation gas. A provision to extend and modify the credit was included in last year's Finance budget reconciliation legislation. The provision was dropped from the bill for reasons unrelated to the debate over extension of the credit. R. Lacy, Inc. urges the Finance

[2] Mere eligibility for the incentive price meets the criteria of Section 29(c)(2)(B). However, most tight formation gas is not actually sold at the incentive price level in today's gas market.

[3] However, gas produced from wells drilled before that date will continue to qualify for the high incentive price until the gas is otherwise deregulated.

Committee to reaffirm its strong support of the Section 29 credit for tight formation gas producers. The company also supports extending the placed in service date for at least two additional years. These changes should be included in any tax legislation the Committee may consider this year.

Enclosures.

LA RUE, MOORE & SCHAFER, INC.,
Dallas, TX, Aug. 14, 1990.

CONFIDENTIAL
Mr. Neal Hawthorn,
R. Lacy, Inc.,
P.O. Box 2146,
Longview, Texas

Re: Tight Formation Gas Reserves, Carthage Field, Panola County, Texas

Dear Mr. Hawthorn: In accordance with your request we have made a study of the economic benefit of the tax credit available to producers of certain low yield (tight) gas formations under Section 29(c)(2)(B) of the Internal Revenue code. While the data used were drawn from our analysis of your company's experience in the Carthage (Cotton Valley) Field of East Texas, the results and conclusions are generally applicable to other gas resources in the tight gas category.

A probability model based on actual Carthage field performance and current economic parameters was used to estimate the chance of economic failure from the point of view of a hypothetical operator developing the field without benefit of hindsight. Using this technique, we are able to view development of a tight gas property through the eyes of a prudent operator as he accesses his risk.

The results of the study are as follows:

1. The quality of any one well prior to its drilling, and even for some time after it's drilling, is unpredictable.
2. The total gas production (reserves) from individual wells completed in tight formations is highly variable.
3. The reserve expectation of a tight gas area under development cannot be known until a number of wells are drilled, completed, and produced for some time. This results in a large high-risk investment just to establish a statistical profile.
4. Highly variable well quality, and generally low reserves increase the probability of economic failure in tight gas sands, as compared to conventional development.
5. If a 10 percent pretax rate of return is selected as the minimum acceptable for risk ventures, the chance of failure in a group of five test wells is 31.5 percent, without the tight gas credit. With the tight gas credit, the chance of failure drops to 10 percent. Producers typically select investments which produce an unrisked proforma rate of return of 25 to 30 percent to compensate for uncertainty in drilling results.
6. Development of tight gas resources is not, in general, a particularly attractive economic venture, however, the availability of a tax credit can enhance the economics to the point where the risks are justified, and permit otherwise unrecoverable gas resources to be developed.

Details of the methodology used in this analysis and the Monte Carlo simulation used in the risk analysis are attached to, and by reference, made a part of this letter.

Very truly yours,

ERIC J. HYMAN, P.E.

Enclosure.

STATISTICAL STUDY OF A TIGHT GAS FORMATION, CARTHAGE FIELD, PANOLA COUNTY, TEXAS

DISCUSSION

History

Section 29(c)(2)(B) of the Internal Revenue Code provides that certain categories of gas produced from low yield "tight" gas formations qualify for a tax credit. The Cotton Valley formation in the Carthage Field, Panola County, Texas, is a tight gas sand for which the credit is conditionally applicable. This study was undertaken to provide insight as to how the availability of the tax credit may drive future development of gas reserves from the Cotton Valley formation, and other similar tight gas resources.

The Cotton Valley In East Texas is productive of natural gas and condensate (a gas by-product) from numerous sand intervals within the formation. Due to the extremely low natural permeability, the sands yield virtually no gas without artificial stimulation (i.e., hydraulic fracturing). Prior to stimulation, the productive quality of any one well cannot be predicted, and even after stimulation, prediction of gas production rates and reserves is impossible until a well approaches a stabilized condition. Reasonable predictions may be made only after several months of uninterrupted flow, or perhaps years, if flow is intermittent.

Exhibit 1 is a list of the original 21 Cotton Valley wells operated by R. Lacy, Inc. in the north area of the Carthage Field, Panola County, Texas. These wells, which were drilled in 1977 and 1978, have established producing trends that permit reliable estimates of their ultimate gas recoveries. The date of first production and estimated ultimate recoverable gas and condensate are shown along with the lease name and well number.

The original spacing of 640 acres was subsequently reduced by the Texas Railroad Commission, to 320 acres (optional), and more recently, to 160 acres (optional). Essentially, this means the original 640-acre units are now allowed four producing wells.

Between May 1989 and May 1990, R. Lacy, Inc. drilled an additional 10 Cotton Valley wells producing from these units. The short performance history and erratic production histories of these 10 wells precludes an accurate estimate of reserves, and they were therefore excluded from our statistical analyses.

Statistical Analysis

Note that reserves from individual wells on Exhibit 1 vary by a factor of ten. This degree of variation is typical of tight gas sands. Based on previous studies, we discovered that engineering and statistical analyses of actual performance data such as this, would provide the basis for a probability model useful in assessing risk in developing a tight gas property. While the results and conclusions are directly applicable to the area of interest, they are generally applicable to other gas resources in the tight gas category.

Exhibit 2 is a production plot representing a composite of the 21 wells listed in Exhibit 1. The production histories were normalized (adjusted to begin production on the same date), totaled, and then averaged according to the well count each month. The first five years of actual production is shown, together with the forecast used for analyzing the economics of an R. Lacy, Inc. Cotton Valley well. The actual production beyond the first five years has been excluded because of distortion in the trend caused by market curtailment.

The shape of this production profile is a good representation of a typical well for this area, a steeply declining production rate for the first several months, followed by many years of a gently declining rate. The basic curve is the same regardless of the ultimate gas recovery. For better wells, the curve would be shifted up, and for lesser wells, the curve is shifted down without a material change in its shape.

Exhibit 3 is a representation of the distribution of ultimate gas recoveries for the 21 wells listed in Exhibit 1. Statistically, each of the 21 recoveries is called an observation, and each represents a data point used in the analysis. The cumulative frequency distribution of the sample was determined by summing the frequencies for successively higher observations. The observations and corresponding cumulative frequency were then plotted on a semi-logarithmic (semi-log) probability scale, with the cumulative frequency shown as "probability." Note that when plotted on this type of scale, the data are a good approximation of a straight line, indicating a log normal distribution. Log normal distributions of well quality are commonly found in tight gas formations.

The 50 percent probability represents the geometric mean, which can be seen in this exhibit to be approximately 1.0 Bcf.[1] Further examination of Exhibit 3 shows that a well drilled on the Lacy Block would have had a 95 percent chance of producing at least 0.3 Bcf, but only a 5 percent chance of producing more than 3.1 Bcf. In other words, 90 percent of the wells can be expected to have resources between 0.3 Bcf and 3.1 Bcf. We say "would have had" because the amount of drainage by the prior 21 wells cannot yet be determined.

Actual results of drilling any one well can fall anywhere within the 0.3 Bcf to 3.1 Bcf range, or even outside the range. In addition, the result of each well drilled is independent of the results of all prior wells. This exhibit, therefore, represents the

[1] Billions of cubic feet. Example: 1 Bcf at $1.00 per Mcf (thousand cubic feet) = $1,000,000

probable result of any well drilled in the area, and can be used as a basis for "mathematically drilling" wells using the Monte Cario technique. The simulated outcome of drilling a number of such using the Monte Carlo technique. The simulated outcome of drilling a number of such wells will be used later to calculate a probable economic result for various tax incentive scenarios.

Exhibit 4 has been calculated from Exhibit 3 to show the same information in the more familiar "bell" curve form. Note that the better wells which are necessary to improve the average drilling results occur infrequently and the chance of getting one in a small sample of test wells is small.

Economics of Development

Exhibit 5 presents unrisked economic results for a typical Cotton Valley well in this geographic area based on the production profile shown in Exhibit 2, and an ultimate gas recovery of 1.0 Bcf, which is the geometric mean from the distribution in Exhibit 3. The following assumptions were used to arrive at these results:

- No tight gas send tax credit.
- A high price of $1 .92/Mcf which was the average price received by R. Lacy, Inc. in 1989. The price is escalated at 3 percent per year beginning January 1, 1992.[2]
- Lease operating expenses of $1,500/month escalated at three percent per year.
- Drilling and completion costs of $1,024,200.
- Corporate tax rate of 34 percent.
- Tax credit of $0.517/MMBTU through December 31, 2000. One hundred percent of the working interest is assumed to be burdened by a 12.5 percent royalty.

Exhibit 6 is identical to Exhibit 5 except the effect of the tight gas sand tax credit has been included in the calculation.

By repeating the economic analysis shown on Exhibits 5 and 6 for different reserve quantities the unrisked pre-tax rate of return can be calculated for each gas reserve quantity, with and without the tight gas credit. The resulting profile is shown on Exhibit 7. An obvious conclusion is that, it takes less gas reserves to produce the same economic result if the tax credit is applied. We will now look at the probability of getting an acceptable economic result and how that probability is affected by the tax credit.

By selecting an actual (rather than hypothetical) example of a tight gas reservoir, we are able to better examine the decision-making process of the gas producer. Our basic economic premise is that the development of a gas field, like any other risk venture, will proceed only if the investor anticipates a return on his capital in excess of alternative "safe" investments; investment-grade bonds, for example. Our experience has been that, because of the inherent risk of capital loss, that no producer would willingly commit investment funds to this type of gas development if he thought the pre-tax risk adjusted rate of return would be less than 10 percent.[3]

Accordingly, for the purposes of this analysis, we have defined gas development ventures producing less than a 10 percent rate of return as economic failures.

Monte Carlo Simulation

Now, assume that a producer intends to develop a group of leases that he believes to be statistically identical to the Lacy Block. His procedure would be to drill a well, evaluate it, and drill another, continuing until the leases are completely developed, or until he was discouraged by the results. If the first few wells were bad, he certainly would not drill all 21 wells.

By Monte Cario simulation techniques, we can mathematically "drill" the lease block, and then based on the results of a reasonable number of evaluation wells (we have chosen 5), make a "producer" decision as to whether or not to proceed. If the initial results are satisfactory, the producer would cause drilling to continue and the reserves would be developed. If not, the project would be dropped and the reserves would not be developed.

From the best-fit line through the distribution of actual gas recovery data (Exhibit 3), recoveries from five wells were randomly chosen, totaled, and then averaged. One hundred repetitions of this procedure provide the data for the frequency distribution curve shown in Exhibit 8.

Although the producer has no way of knowing the outcome of any five-well evaluation program, the curve on Exhibit 8 provides a means of predicting his chances of a successful venture. For any point on the curve, the chance of achieving an aver-

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[2] Although the current price being received by R. Lacy, Inc. (May 1990) is $1.64/Mcf, we have chosen, for the purse of this study to use Lacy's average 1989 price of $1.92/Mcf and escalate that price at 3 percent per year.

[3] Unrisked minimum criteria for investment usually fall in the 25 to 30 percent range.

age recovery (for a five-well test program) equal to, or less than, the recovery defined on the horizontal scale, is determined by the corresponding probability on the vertical scale. For example, there is a 31.5 percent chance that a five-well drilling program will average 1.0 Bcf, or less.

Exhibit 8 can be used in conjunction with Exhibit 7 to access the risk associated with developing Cotton Valley tight gas properties. In this example, our hypothetical producer's economic criteria for a failed venture was a 10 percent pre-tax rate of return. Therefore according to Exhibit 7, the group of five test wells must average, at least, 1.0 Bcf per well in order to achieve this return without the tax credit. By comparison only 0.80 Bcf per well would be required if the tax credit were available to the producer.

From Exhibit 8, we can conclude that without the tax credit, the chance of having a failed venture would be 32 percent. However, the risk of failure would be reduced to 10 percent if the tight gas tax credit is included. This is a material reduction in risk and would tend to support development of tight gas resources.

Clearly, after taking into account other risks in drilling, uncertainty of gas markets, other alternative investment opportunities, and a 32 percent chance of failure, a prudent producer would be unlikely to continue developing the block. Even with the tax credit the economics of this venture are poor.

Most producers will make the foregoing analysis intuitively rather than explicitly, but each will make the analysis. He knows that its makes no difference how close something comes to being economic, as long as its not economic it won't get done. The tight gas tax credit goes a long way toward reducing economic risk and it's availability will, no doubt, permit the economic development of otherwise unrecoverable gas resources.

EXHIBIT 1

NORTH AREA WELLS
Carthage (Cotton Valley Field)

NO.	WELL NAME	DATE OF 1st PROD	ULTIMATE RECOVERY GAS MMCF	OIL/COND MBBL
1	BRIGGS #1-2	09/77	2553.124	15.456
2	BROWN, J. C. #3	06/78	865.895	20.474
3	BURNETT #1-2	06/78	267.883	10.837
4	BURNETT #2-3	06/78	961.372	5.263
5	BURNETT #4-3	08/78	1707.417	27.069
6	BURNETT #7-15	12/77	1977.346	24.136
7	BURNETT #9-3	06/78	735.100	15.814
8	BURNETT #10-4	06/78	702.913	8.978
9	BURNETT #11-11	06/78	1413.066	18.379
10	CAMERON #1-3	12/77	2577.012	22.303
11	CAMERON #2-3	12/77	1381.819	16.460
12	CAMERON #3-4	12/77	944.372	14.922
13	COOKE, J. W. #1-2	04/78	615.268	11.832
14	COOKE, J. W. #2-4	12/77	509.697	17.548
15	HOLT #2	08/78	342.781	6.142
16	METCALF #2	12/77	1505.398	17.582
17	PARKER #1-8	10/77	608.014	6.803
18	PARKER #2-3	10/77	627.442	9.001
19	RICHARDSON #3	04/78	4370.768	71.670
20	ROCQUEMORE #1-2	10/77	1591.707	6.816
21	TURNER #2	05/78	1515.989	17.155
	TOTAL		27774.383	364.640
	AVERAGE		1322.590	17.364

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EXHIBIT 2

TYPICAL GAS PRODUCTION PROFILE
Carthage (Cotton Valley) - North Area
Average of 21 R Lacy Operated Wells

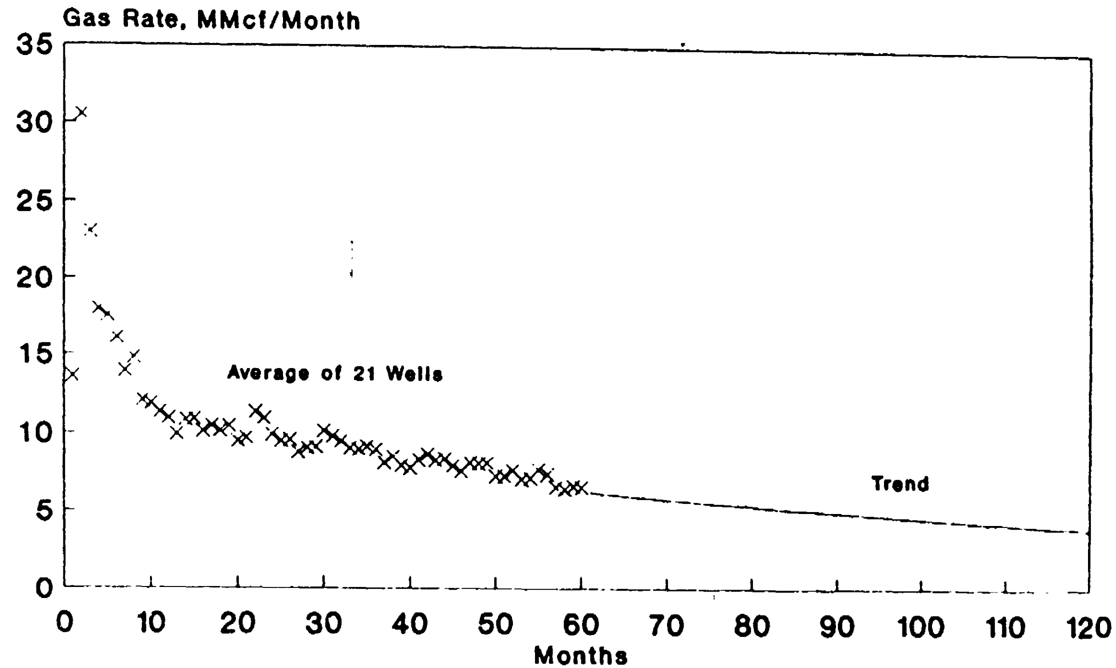

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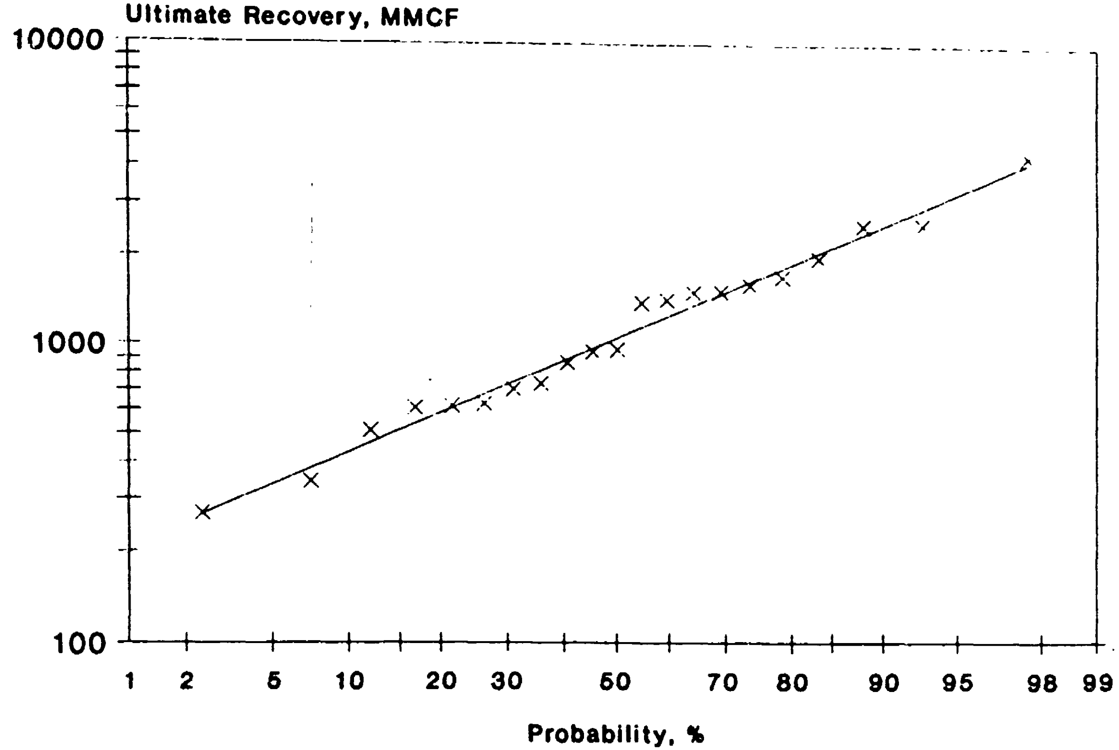
EXHIBIT 3

FREQUENCY DISTRIBUTION
Carthage (Cotton Valley) - North Area



21 Wells (see Exhibit 1)

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LA RUE, MOORE & SCHAFER, INC.

EXHIBIT 4

FREQUENCY DISTRIBUTION
Carthage (Cotton Valley) - North Area

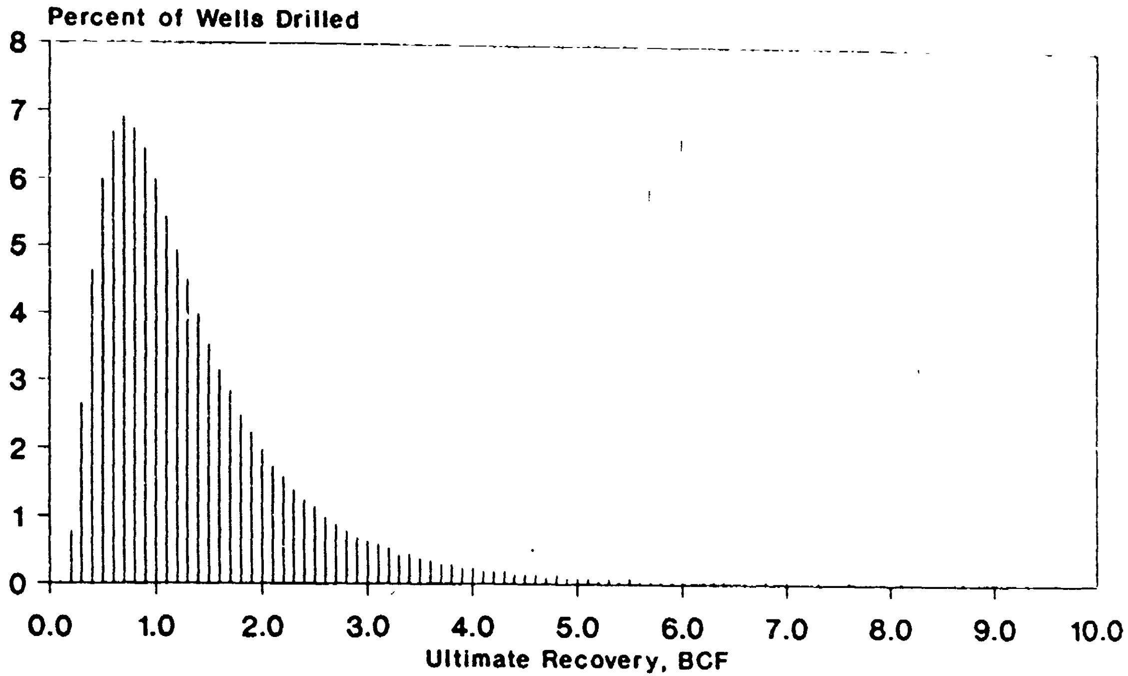

EXHIBIT 5

UNRISKED ECONOMICS
SAMPLE WELL
WITHOUT TIGHT SAND TAX CREDIT

AS OF 6-01-90

NORTH AREA
CARTHAGE (COTTON VALLEY) FIELD
PANOLA COUNTY, TEXAS
R. LACY, INC. - OPERATOR

-END- MO-YR	GROSS OIL MB	GROSS GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	TOTAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-90	1.980	112.643	218.026	10.500	207.526	1024.200	32.038	.000	.000	-816.674	-822.337
12-91	1.864	114.313	222.505	18.291	204.214	.000	54.907	33.376	.000	204.214	-638.087
12-92	1.315	88.731	175.980	18.840	157.140	.000	39.213	26.397	.000	157.140	-509.198
12-93	1.032	76.493	154.691	19.405	135.286	.000	28.003	23.204	.000	135.286	-408.322
12-94	.851	69.311	143.038	19.987	123.050	.000	20.021	21.456	.000	123.050	-324.910
12-95	.706	63.213	133.214	20.587	112.627	.000	20.021	19.982	.000	112.627	-255.504
12-96	.586	57.399	123.657	21.204	102.453	.000	20.021	18.549	.000	102.453	-198.108
12-97	.521	52.119	115.457	21.841	93.616	.000	4.157	17.318	.000	93.616	-150.430
12-98	.473	47.325	107.982	22.496	85.486	.000	.000	16.197	9.024	76.463	-115.029
12-99	.430	42.973	100.992	23.171	77.821	.000	.000	15.149	21.309	56.512	-91.243
12 0	.390	39.020	94.454	23.866	70.588	.000	.000	14.168	19.183	51.405	-71.573
12 -1	.354	35.431	88.339	24.582	63.757	.000	.000	13.251	17.172	46.585	-55.368
12 -2	.322	32.172	82.620	25.319	57.301	.000	.000	12.393	15.269	42.032	-42.076
12 -3	.292	29.213	77.272	26.079	51.193	.000	.000	11.591	13.465	37.728	-31.230
12 -4	.265	26.526	72.269	26.861	45.408	.000	.000	10.840	11.753	33.655	-22.435
S TOT	11.382	886.881	1910.496	323.029	1587.467	1024.200	218.380	253.871	107.174	456.094	-22.435
AFTER	1.675	167.550	529.901	338.728	191.173	.000	5.820	64.752	41.004	150.169	5.585
TOTAL	13.058	1054.431	2440.397	661.757	1778.640	1024.200	224.200	318.623	148.178	606.262	5.585

	GROSS	W.I.	NET
INITIAL INTEREST	1.00000	1.00000	.87500
OIL RESERVES, MB	13.058	13.058	11.425
GAS RESERVES, MMF	1054.431	1054.431	922.627
NGL RESERVES, MB	.000	.000	.000
SGS RESERVES, MMF	.000	.000	.000
REVENUE, M$	2789.027	2789.027	2440.396
OPER. EXPENSE, M$	661.757	661.757	661.757
TANGIBLES, M$	224.200	224.200	224.200
INTANGIBLES, M$	800.000	800.000	800.000
INITIAL OIL PRICE	16.500		
INITIAL GAS PRICE	1.922		

	BFIT	AFIT
RATE OF RETURN, PCT.	11.5	10.2
UNDISC. PAYOUT, YRS.	6.4	6.4
DISC. PAYOUT, YRS.	13.3	19.3
UNDISC. NET/INVESTMENT	1.7	1.6
DISC. NET/INVESTMENT	1.1	1.0
DISCOUNT %	10.00	
LIFE, YRS.	25.2	
GROSS OIL WELLS	.0	
GROSS GAS WELLS	1.0	

P.W. %	BFIT P.W. M$	AFIT P.W. M$
5.00	314.306	233.411
10.00	51.980	5.585
15.00	-117.696	-145.452
20.00	-234.933	-252.148
25.00	-320.312	-331.328
30.00	-385.150	-392.392
35.00	-436.067	-440.941

LA RUE MOORE & SCHAFER INC

BEST AVAILABLE COPY

EXHIBIT 6

UNRISKED ECONOMICS
SAMPLE WELL
WITH TIGHT SAND TAX CREDIT

AS OF 6-01-90

NORTH AREA
CARTHAGE (COTTON VALLEY) FIELD
NORTH AREA
PANOLA COUNTY, TEXAS
R. LACY, INC. - OPERATOR

-END- MO-YR	GROSS OIL MB	GROSS GAS MMF	REVENUE TO INT. M$	OPER. EXPENSE M$	NET INCOME M$	TOTAL INVEST. M$	DEPR. M$	DEPL. M$	INCOME TAX M$	CASH FLOW M$	CUM. NET PW M$
12-90	1.980	112.643	280.391	10.500	269.891	1024.200	32.038	.000	.000	-754.310	-761.675
12-91	1.864	114.313	285.412	18.291	267.121	.000	54.907	33.376	.000	267.121	-520.668
12-92	1.315	88.731	224.464	18.840	205.624	.000	39.213	26.397	.000	205.624	-352.011
12-93	1.032	76.493	196.219	19.405	176.814	.000	28.003	23.204	.000	176.814	-220.169
12-94	.851	69.311	180.446	19.987	160.458	.000	20.021	21.456	.000	160.458	-111.400
12-95	.706	63.213	167.148	20.587	146.561	.000	20.021	19.902	.000	146.561	-21.083
12-96	.586	57.399	154.326	21.204	133.122	.000	20.021	18.549	.000	133.122	53.495
12-97	.521	52.119	143.275	21.841	121.435	.000	4.157	17.318	.000	121.435	115.340
12-98	.473	47.325	133.242	22.496	110.746	.000	.000	16.197	9.024	101.723	162.437
12-99	.430	42.973	123.928	23.171	100.758	.000	.000	15.149	21.309	79.449	195.878
12 0	.390	39.020	115.281	23.866	91.415	.000	.000	14.168	19.183	72.232	223.516
12 -1	.354	35.431	88.339	24.582	63.757	.000	.000	13.251	17.172	46.585	239.721
12 -2	.322	32.172	82.620	25.319	57.301	.000	.000	12.393	15.269	42.032	253.013
12 -3	.292	29.213	77.272	26.079	51.193	.000	.000	11.591	13.465	37.728	263.859
12 -4	.265	26.526	72.269	26.861	45.408	.000	.000	10.840	11.753	33.655	272.655
S TOT	11.382	886.881	2324.633	323.029	2001.604	1024.200	218.380	253.871	107.174	870.230	272.655
AFTER	1.675	167.550	529.901	338.728	191.173	.000	5.820	64.752	41.004	150.169	300.674
TOTAL	13.058	1054.431	2854.534	661.757	2192.777	1024.200	224.200	318.623	148.178	1020.399	300.674

	GROSS	W.I.	NET
INITIAL INTEREST	1.00000	1.00000	.87500
OIL RESERVES, MB	13.058	13.058	11.425
GAS RESERVES, MMF	1054.431	1054.431	922.627
NGL RESERVES, MB	.000	.000	.000
SGS RESERVES, MMF	.000	.000	.000
REVENUE, M$	3262.326	3262.326	2854.532
OPER. EXPENSE, M$	661.757	661.757	661.757
TANGIBLES, M$	224.200	224.200	224.200
INTANGIBLES, M$	800.000	800.000	800.000
INITIAL OIL PRICE	16.500		
INITIAL GAS PRICE	1.922		

	BFIT	AFIT
RATE OF RETURN, PCT.	19.8	19.2
UNDISC. PAYOUT, YRS.	4.2	4.2
DISC. PAYOUT, YRS.	5.9	5.9
UNDISC. NET/INVESTMENT	2.1	2.0
DISC. NET/INVESTMENT	1.3	1.3
DISCOUNT %	10.00	
LIFE, YRS.	25.2	
GROSS OIL WELLS	.0	
GROSS GAS WELLS	1.0	

P.W. %	BFIT P.W. M$	AFIT P.W. M$
5.00	659.115	578.219
10.00	347.069	300.674
15.00	140.603	112.847
20.00	-4.630	-21.846
25.00	-111.849	-122.865
30.00	-194.103	-201.345
35.00	-259.182	-264.057

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EXHIBIT 7

ULTIMATE RECOVERY vs RATE OF RETURN
Carthage (Cotton Valley) - North Area

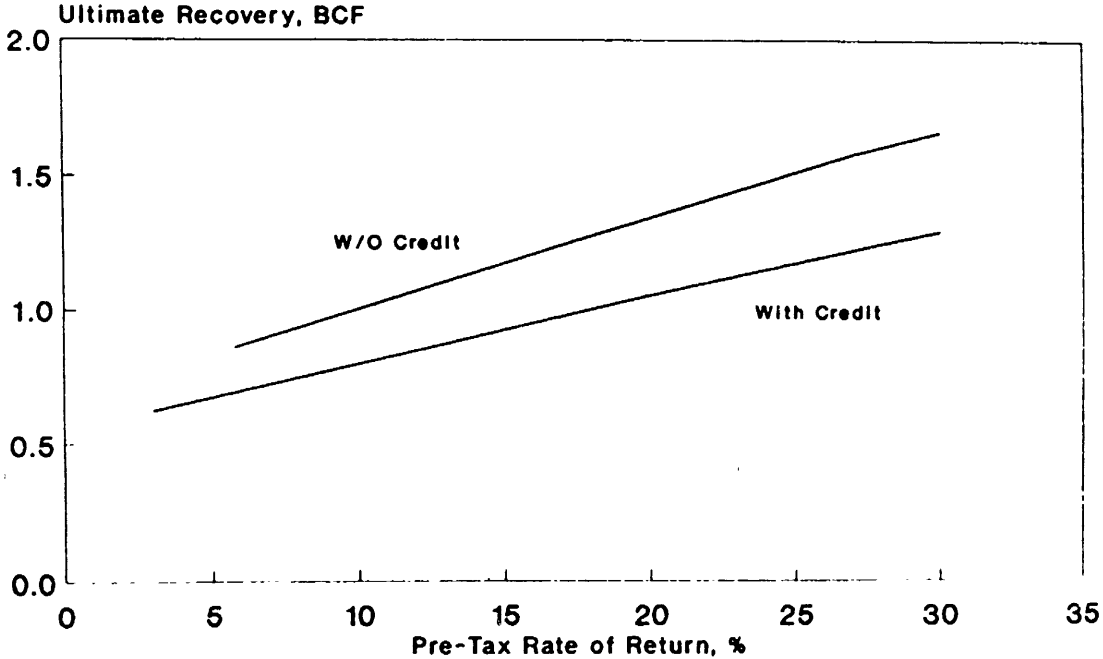

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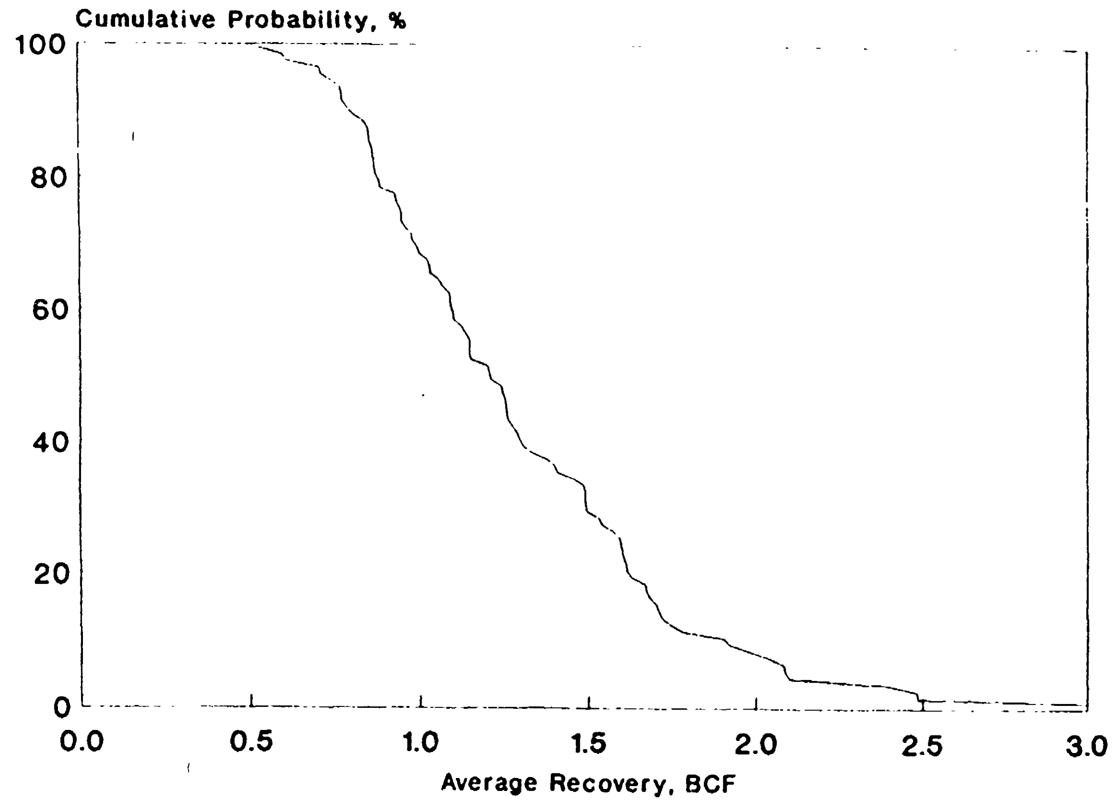
EXHIBIT 8

MONTE CARLO SIMULATION: 5 WELL PROGRAM
Carthage (Cotton Valley) - North Area



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