

THE IDEAL PETROLEUM TAX REGIME

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Abstract

Seldom have two such divergent entities become partners; government mineral resource owner and private oil and gas exploration and production company. The latter thrives on risk and uncertainty, while the former finds those characteristics troublesome and undesirable. Ordinary non-sinister events in the life of an oil company might well be cause for "investigation" by political groups if they took place within the government. One can almost imagine the formation of a Citizens Commission Against the Drilling of Dry Holes.

Differences or not, the ideal tax regime must allow each of the partners to go in with the expectation of becoming a winner and leave as a winner anxious to consummate another partnership. Many contracts today do not even come close to this ideal.

In searching for the ideal tax regime, this paper examines the foundation of taxes, royalties, profit sharing and complicated contracts. All of these work to reduce the amount of oil and gas developed, minimise opportunity for oil and gas companies and, perhaps worst of all, cost the host government and its citizens large sums of money that might otherwise be collected as rent on its mineral resources.

Combining the above analysis with an understanding of the highly ambiguous nature of the exploration business, we find that both host and explorer/developer do better when there are few restrictions on gathering information prior to drilling. Further, the host may increase the value of its holdings by a factor of two if it will give up intricate taxes, royalties and profit sharing agreements for a simple annuitised/deferred cash bonus.

Introduction

Is there such a thing as an ideal tax regime? Since we can resolve only part of the question analytically, there may never be such a regime that all can agree on. But certainly we can think of improvements to present systems around the world and get a different kind of debate under way.

Heretofore, questions about making tax regimes better started with the assumption that nations must tax the development of their resources and thus the only question was how to do so better. I have taken a different approach. First throw away the assumption that we must have taxes, royalties, production sharing, carried interests, etc. Instead let us start where we should, at the beginning.

First principle: An owner of a resource wants to maximize the value of that resource. By that we mean that the owner wants to convert that resource into money in some optimum fashion. Notice that "optimum" does not necessarily mean to produce as fast as you can. Depending on markets and pricing, there may be less aggressive development programmes that bring more value to the owner. Optimum also means optimum for a particular owner. Different owners have different values and so must construct regimes that optimise for them.

The method I lay out, however, may satisfy many owners, and may even surprise a few. What if I suggested that a resource owner could increase the cash value of his or her resource by a minimum of 50 % by setting taxes, royalties and shared profits, for example, to zero?

Present Inefficiencies

Figure 1 shows the revenue split from a typical offshore development project of 100 million barrels of oil with a 5 %

chance of discovery. The tax, royalty, and carried interest approximate what you have in New Zealand. (Incidentally, none of the figures I use in this paper come from real projects. Instead, I have chosen to use generic and reasonable assumptions with which to build examples. In general, I have assumed allowance for recovery of exploration costs. Cost recovery takes place at an accelerated pace. Quite high; fixed operating costs as one might expect in remote development are assumed. Other key assumptions are; \$21/barrel oil price and a 10 % production decline rate. (But please note that none of these assumptions about details is critical to the arguments that are developed).

Why say that the present system is inefficient? It is inefficient because to administer the taxes, royalties and profit shares, for example, takes people and time. Even the calculations are not trivial. When a company faces a myriad of different ways of paying the owner, the company has to set up its own bureaucracy to account for it all. The company also faces uncertainty because the various rates can change at any time and may affect projects already under way. In addition to the added staff required by the explorer/producer, the host government must also set up a bureaucracy to administer the system. It must monitor production and costs to assure that the payments it receives properly reflect the contract terms.

Who pays for all the costs associated with the conventional systems of taxing resource development? I think the owner or host government. The simplest explanation stems from the way oil companies handle costs internally. In most instances, such costs are tax deductible with the result that the government tax take reduces as costs increase. That part of the costs not recovered through the tax effect shows up as

a lower value on the project itself. These costs prevent the explorer/developer from offering as much "up front money" in bonuses or work commitment or engineering talent. Forced into providing a rate of return to its owners, the oil companies must pass these costs on, and most often to the consumer of the product.

Clearly, that part of the costs associated with the host government get paid by the host. Technically, these costs come out of the taxes and royalties paid. But that cost could be greatly reduced if the host were to find a way to receive the same or more money for its resource without requiring the bureaucracy.

Notice also (Figure 1) that the bulk of the cash flow goes to the producer prior to pay out of the investments. After that time, the greatest portion of the revenue goes to the host and to fixed operating costs. Consider the position of the developer at about year 14. Incentives to employ the best talent to increase production drop because the reward from such effort will be minimal. Contrast the developer's incentive in Figure 1 vs. his incentive in Figure 2 where he or she gets all the revenue from the project throughout project life. Incentives to increase production are very high because all the reward flows to the developer.

But such a picture implies that the host simply gives the resource to the developer — not a very likely scenario. Figure 3 illustrates another kind of split where the developer gets all the cash flow but the host also receives a substantial rent for the resource. In this hybrid system, the cash to the host has been disassociated from the project revenue so that it does not serve as a brake on the developer's incentives.

In order to achieve our goal of greatly reduced transaction costs from both host and developer, and to gain the advantages of the cash flow depicted in Figure 3, a host government could move to a 100% deferred cash bonus system for getting its rent. Remember our goal was to maximize the value of the

resource to the host. A specially constructed cash bonus will return a higher rent to the host than any combination of taxes, and royalties. Let us lay the foundation for that statement.

Competitive Assumptions and Historical Returns

Oil companies cannot make whatever rate of return they wish. The shareholders want a 50% return (or 100% or any other large number) but must settle for what the market place allows. Pushing the number up, we have the demands of the shareholders, but the forces of competition keep shoving it down. Where does it end up?

Figure 4 shows a ten year moving average of real return (i.e. after inflation) for non tax paying owners of a portfolio of United States (U.S.) oil companies. The variability, even with over 30 years of data, may seem surprising. An unprecedented bull market in the U.S. from 1949 to 1956 dominated the moving average from the late 1950s to the early 1960s. The Standard and Poor Industrial Index climbed at over 20% per year compounded; oil stocks were no exception and in fact moved at a slightly higher rate.

This period, coming out of World War II and including the Korean conflict, saw more growth and less price inflation than during any period in U.S. history. (See the SRC CENTURY-PLUS CHART of Investment and Economic History published by Securities Research Company of Boston, Mass., U.S.A.) For predictive purposes, I would not start looking at Figure 4 until about 1961. From that point on through 1990, the most dramatic departure from the oscillations around the 5% rate occurred from 1975 through 1979. In the U.S. that was the period of price controls on crude oil coupled with the highest sustained price inflation in U.S. history, being rivalled only by those inflations associated with the War of 1812, the Civil War and World War I.

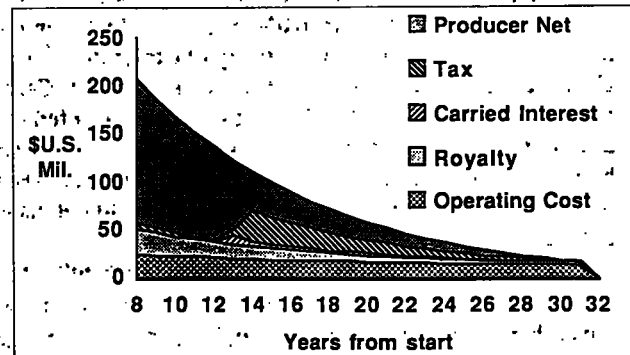


Figure 1: Splitting the pie.

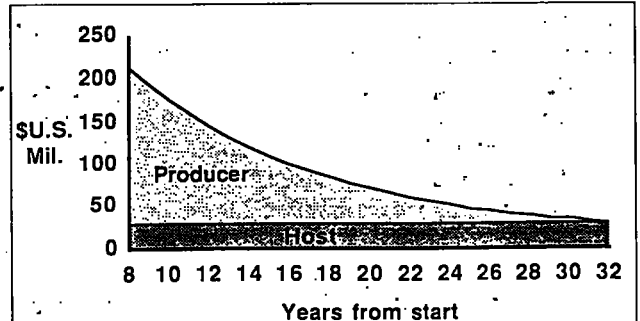


Figure 3: Producer and host cash flows with deferred bonus.

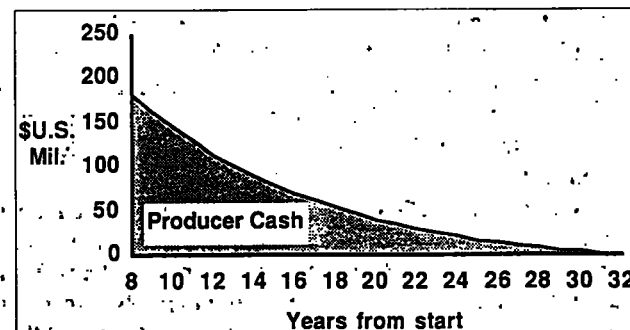


Figure 2: Producer cash flow with no tax and royalty.

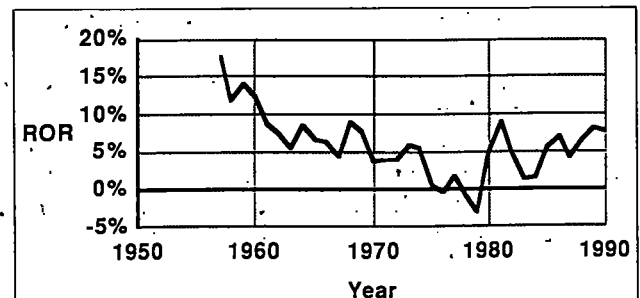


Figure 4: Return from U.S. domestic oil company portfolio; ten year average.

Assuming we can ignore the two periods described (a highly dangerous act, in a world of surprises), and we believe the future holds similar returns in store as has the past, then we can assume that shareholders in the future will end up with about 5% return over inflation.

You may fairly ask how that return compares to less risky corporate and government bonds. From 1960 through 1990, a U.S. government bond would have yielded 2.2% after inflation while a high grade U.S. corporate bond (Aaa) yielded 3.3%. It all seems consistent since one would expect a higher return for the more risky equity holdings. (The bond rate information comes from the *Statistical Abstract of the United States* while the oil company portfolio data comes from Securities Research Company mentioned earlier.) Another caveat, real bond rates have been abnormally high during the decade of the 1980s in the U.S. due either to high demands for money from the government to cover spending deficits, decontrolling of financial markets in the 1970s that led to generally higher interest rates, or a fear of returning inflation above the 4% now seen.

If the shareholders get around 5% and the bond holders about 3% (1% cost to the company after deducting interest expense and inflation) then the companies have been investing at a rate equal to the weighted average of these two numbers depending on the size of the debt to equity ratio. That averages a little over 3% real return. (It would be improper to use accounting numbers such as return on capital employed, for this exercise, because they have no meaning in this economic context). Even though this average fits U.S. oil companies, it may not work for all companies everywhere. In each country, investors set their own goals as a function of the peculiar risks and opportunities that exist there.

The government interest rate also demands some analysis. Paying 2.2% over inflation may seem low enough, but when you correct for the fact that government taxes the interest it pays to its citizens, you see that the effective interest rate to government may be zero or even less. Let us say, for example, that the government pays 6% interest but levies a 33% tax. That leaves the bond holder with 4%. Let us say that inflation is 4%. Now the bond holder has nothing. Of course not all bond holders pay taxes, so the true interest cost to the government may be higher.

This preamble sets the stage for the following conclusions:

- Oil industry profits do not reach as high as some think.
- Government net real interest rates may be zero or even less.

For this paper, I have used 6% as a future equity return for the oil industry to honour the view of many that potentially increasing oil prices may lead to higher returns and to recognize the higher than normal bond rates of recent years. If that trend persists, the industry will have to increase its return over its historical average or lose out in competition for capital. I have also used 0% for the net real interest rate for industrialized nations. The arguments will not change as long as the equity return in the stock markets exceeds the government's real net interest rate.

Further, I have assumed that oil companies will make an average of 5% on their total investments after taxes and inflation. If a company cannot find a deal that makes at least 5%, then the company just looks elsewhere. Hosts whose contract terms do not allow for this return will not attract producers to develop their resources.

Cash Bonus

In a competitive environment, companies find themselves driven to the lowest return consistent with the demands of those who put up the capital. That means that if a host government puts up some of its resources at auction, the explorer/developers will bid until they reach their lower limit of 5% return and then they will stop. The resource value over and above the 5% return goes to the host in economic rent. The previous statement does not depend on the terms of the contract as long as we understand the components of the rent: cash bonus, royalty, taxes, and profit sharing, for example.

A company whose contract specifies no royalty will simply put the present value of the royalty into the cash bonus. Otherwise, the company would violate its 5% return target. The same applies for taxes or any other method host governments use to extract rent. As happens in a competitive situation, the host should get all of the rent no matter how it designs its contract. But some contract terms may limit the rent because they add to costs. For example, fuzzy contract terms lead to uncertainties beyond those normally associated with the oil business, and will certainly lead to higher costs. In a competitive bidding situation, the bidder would be willing to pay less for acreage under these more costly terms than he or she would pay for acreage covered by a simpler contract. The host therefore pays the cost of complicated contracts.

Where cash bonus bidding is absent, the contracts do get fairly involved as hosts try to make the contracts deal with the highly variable world of oil and gas exploration. Trying to get a contract to extract the economic rent when no one knows the reserves size can be a strain. With cash bonus bidding, all those size differences just get built into the size of the bonus leaving out the necessity of trying to find contract language to fit.

Thus we have no problem in getting all the economic rent for the host built into a cash bonus system. That contract becomes amazingly simple: The producer pays all the money up front and from then on all production belongs to him or her. When one goes to the grocery store and buys a potato, the store does not follow the customer around to extract royalties on the use of the potato:

With an 100% cash bonus system, the calculations on both sides are amazingly simple. No rooms full of people worrying about taxes and royalties to be paid. No rooms full of government people to collect and monitor tax and royalty payments. The money is paid initially. And, it comes whether or not the acreage produces! The industry pays money for parcels that never produce a drop of oil. Assuming both sides live up to the contract, the producer will never have to worry about some change in tax laws because there are no taxes.

That point may seem strange to some. Should one industry escape its fair share of taxes? Of course not. But this paper deals with a government maximizing the rent from its own resource. It's not like taxing some other industry working on non-government resources. If a tax on the profits of a producer of government resources does not bring in as much money to the government as some other way of getting the rent, then it seems quite clear that the tax should be removed. Actually, the taxing just takes place in

a different form. Instead of calling the initial cash a bonus, why not call it a prepayment of tax? In effect, that is exactly what it is. (A non-trivial aside: the U.S. government taxes its oil companies again if it perceives they are not taxed sufficiently by foreign governments. The U.S. would have to recognize that bonuses and taxes have no fundamental difference in the competitive bidding context or else put their own companies at a disadvantage in the bidding process. Since the U.S. could benefit from new supplies of oil in New Zealand and other nations, it would certainly have an incentive to take a statesman-like view of this problem.)

I want to look at the effect of changing the tax rate for an exploratory venture that looks for a 100 million barrel field with a 5% chance of discovery (Figure 5). The chart assumes 19 dry holes and a discovery well leading to the development and production of 100 million barrels. With a 70% tax rate, the explorer/producer would walk away from the contract prior to any effort. He or she could not make a rate of return and 70% of nothing is nothing. The host gets nothing. At a 66% tax, the venture meets the criterion return for the explorer/developer, and the contract is signed. The present value of the tax receipts to the host is about \$450 million dollars, but only on the well that hits. Most of the time the host gets nothing.

If the host reduced the tax rate (see dashed line) then the host would get less of the rent while the explorer/developer would get more. But if the host were to set a 30% tax rate with a front end bonus, the host would capture a present value of slightly over \$600 million; a \$150 million improvement. In addition, some of that money comes in guaranteed whether the exploration wells hit or not, because explorer/developers pay bonuses for parcels that are not successful.

The Figure 6 chart differs only a little from Figure 5, in that it shows the amount the explorer/developer would bid to just make the criterion return at the various tax rates. Paradox: The host lowers the tax rate and makes more money. Moreover, the more the tax falls the more guaranteed money the host gets. How?

An Annuity

We now take the cash bonus and turn it into a cash flow stream that approximates the taxes and royalties that the host would have received had it stayed with traditional contracts. The secret of increasing the value of the cash bonus comes about from noticing the difference in discount rates between the host and the explorer/producer.

Let us return to the idea of a deferred bonus. Let us say that the bidder does not pay the money initially but promises to pay so much each year for 20 years after the discovery begins producing. (The 20 year payments approximate that time that the host would have been receiving taxes and royalties from the production). The amount paid has nothing to do with the size of the discovery, and in fact would be paid even if there were no discovery. Remember, winning companies promise the deferred bonus on prospects that fail as well as those that succeed. To get the amount of the deferred bonus, a company would simply compound the time zero cash bonus forward to the beginning of production at its discount rate and at that time "purchase" an annuity that would make equal payments to the host over the next 20 years.

Think of the cash bonus in two pieces, B_v is that part of the bid based on the after tax value of the prospect, and B_t is

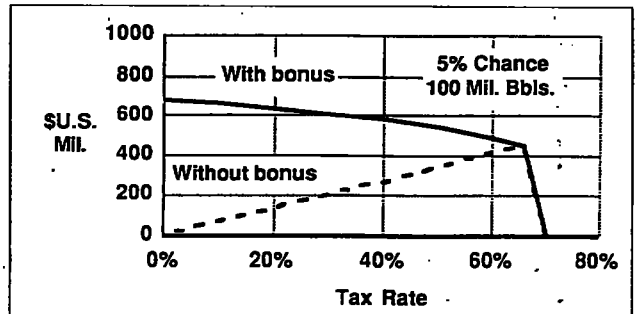


Figure 5: Host NPV vs. tax rate with and without bonus bid.

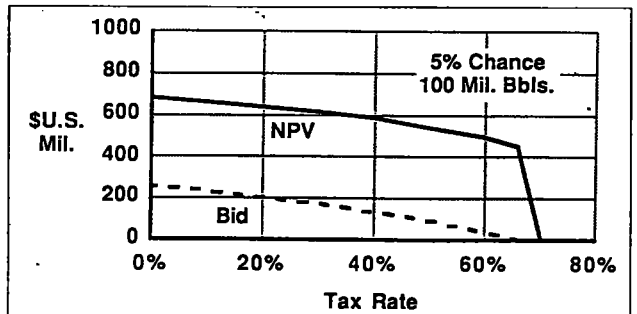


Figure 6: Host NPV and producer bid vs. tax rate.

that part of the bid based on taxes and royalties that are no longer required. (Let's call them untaxes.) B_v represents a portion of economic rent not now being captured by the host because of the imperfection of standard contracts. As part of an annuity, the B_t portion would not change much since the company would discount it back and then compound it forward at the same rate.

Theoretically, this scheme would bring the host more than it can now get with its present contracts and do so with style and simplicity. However, what guarantee would the host have that the bidder would actually have the money later on? What if all the wells are either dry or very small and the bidder has too little cash flow with which to pay the deferred bonus? Or the bidder goes bankrupt in some venture far from New Zealand that severely affects his or her ability to meet his commitment? With all the best intentions, these events can happen.

Another possible solution would be for the bidder to place the bonus in an escrow account administered by a third party (a widely known and respected financial institution) that would create an annuity for the host to be paid independently of the subsequent fortunes of the bidder. However, the effective interest rate on the annuity would have to be as large as the discount rate for the bidder; or the host would lose. Example: Bidder discounts untaxes etc. back to time zero at 5% while a third party institution compounds the bonus forward at 4%. The host ends up with less than they started with unless the value portion of the bid and transaction costs more than makes up the difference.

The third party could invest the proceeds into a portfolio of securities that historically do as well as, or better than the petroleum industry. In fact, why not just use a portfolio of U.S. oil companies as the vehicle for the annuity? Suddenly, the host gains another advantage. Earlier, I described the historical returns for equity owners compared to the companies they owned. I showed a 5% average return to a

shareholder of a company that only made 3% return because the shareholder's funds were leveraged with a bondholder whose interest cost the company only 1%. (These numbers sound very low because inflation and taxes have been removed) Under these conditions, the bidder would discount untaxes for example, at 3%, but the portfolio would increase them to 5%. The value portion of the bid enjoys the same boost.

A colleague of mine has pointed out that the third party could serve another very useful function. If the host changes the rules during the life of the contract to the detriment of the producer, the third party simply cuts off any more payments to the host. A provision such as this can actually benefit the host in that it tends to remove some political risk for the producer and allows him to bid even more up front. The host, much like the owner of a gambling establishment, profits more from a scrupulously honest game than if the rules were changed to gain further advantage.

As explained earlier, I used 6% for portfolio growth (including dividend reinvestment) and 5% for untax discounting by the bidder. Typically, in harsher areas such as offshore, the time between payment of bonuses and the start of production is several years. For this example I use eight years to allow for delays, exploration, drilling, delineation, construction and installation of facilities, and development. The portfolio has been growing all this time at an assumed 6% real return. Since the U.S. does not tax foreign government profits on securities holdings, the entire 6% goes to the host.

At the beginning of production, the host starts taking funds out of the portfolio. By the end of field life the last dollar will have been taken out. This is exactly how Figure 3 was constructed. The money comes to the host over the same period that it would have received taxes and royalties, except that more money comes in than would have arrived through taxes and royalties. The host has used the resources in a most efficient and almost risk free way. (As a practical matter, the "annuity" need not be tied exactly to field life, and in fact for dry holes there is no field life.)

Value of Information

From the example in Figure 7 the host captures almost a billion dollars. This differs from the previous figure only in chance, 30% versus 5%. Anything that the host can do to increase the chance of success for the explorers will bring a great deal more rent to the host. Incentive!

Example: Many hosts want to extend command and control to the seismic survey part of the effort. The logic makes sense. Sign a competent company to do the exploration and it will run its seismic survey, find the best prospects, and drill them. However, exploring for petroleum deposits is a much more uncertain venture. The logical strategy described above would work if the seismic data were definitive. It is not. Every company looks at data in different ways. They use different processing techniques and they are staffed with people of different backgrounds and experience.

Consider the analogy of getting reports from a group of witnesses describing an accident that happened suddenly in the middle of the night. The descriptions are not the same. Figure 8 illustrates the point with real data. Cross plots of bids by two major oil companies in a series of recent sales by the U.S. government are presented. There is little or no correlation between the bids of the companies. This suggests

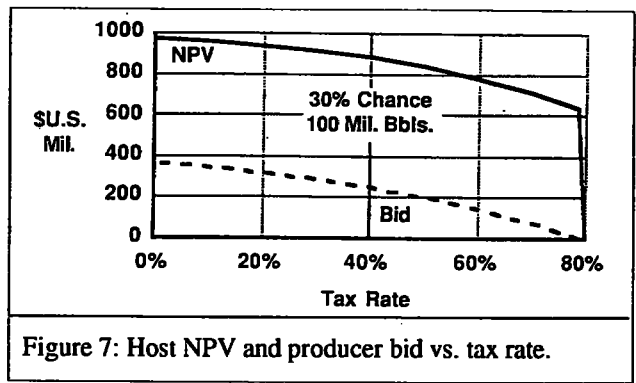


Figure 7: Host NPV and producer bid vs. tax rate.

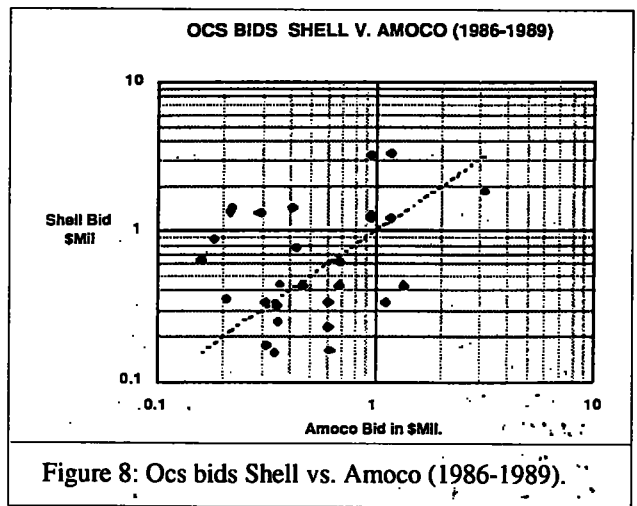


Figure 8: Ocs bids Shell vs. Amoco (1986-1989).

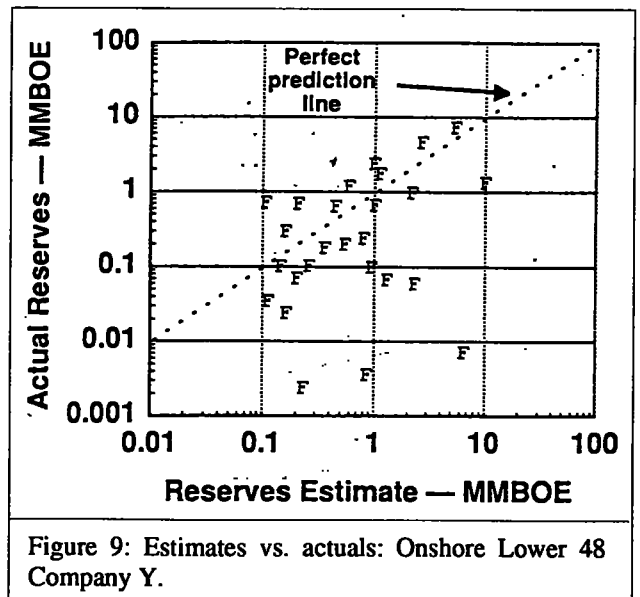


Figure 9: Estimates vs. actuals: Onshore Lower 48 Company Y.

some very different views of the prospects. (Disagreements over future prices or cost of capital will tend to move all the bids by one company up or down compared to their competitor and will not affect the scatter).

Such evidence leads to the conclusion that even the most competent explorer will probably not "see" what lies beneath the surface prior to drilling. The explorer may come up with ideas but not necessarily superior to the ideas of others. If a host allows 50 people to run seismic surveys on an area, those explorers may come up with 50 different ways of looking at the data. The host's chance of getting the best prospect drilled, increases as the number of people (with independent data) participating increases. Thus, having multiple surveys does not constitute waste but rather adds value to the exploration process.

Conventional logic may not work for setting data gathering rules. A host should probably turn its property over free for surface geology and seismic surveys and not be concerned about getting all that data for its own files. Competition will drive the companies to pay more for the concessions. At the same time, competing companies need to feel that they have an advantage because of their particular skills at interpreting the data. If they have to give up that knowledge to the host, they will feel less able to compete and so may offer less for the prospects in initial cash. That decrease, of course, comes right out of the host's pocket.

In addition, the oil company has all the transaction costs of providing data to the host, and costs by the host in trying to understand what they mean. One of the hardest lessons for governments to learn is that market competition will bring fair market price to the host without need for oversight. In the U.S. the government goes to great expense to evaluate property prior to lease sales. They reason that it is the only way to keep the auction honest, and that bidders will not pay top prices if the seller does not know the value of the property. But the government's estimate of value is just an estimate like that of everyone else and so cannot be definitive.

Through the years, I have been able to see pre-drilling reserves estimates compared with post drilling results for several companies (Figure 9). The data above come from estimates in familiar areas for explorers, the onshore portion of the 48 contiguous states of the U.S. Yet the estimates fall far short of being acceptable by most standards. It's easy to miss an estimate by a factor of 4 or more. However, I'm not faulting the petroleum explorers. They do the best they can with the highly ambiguous data they collect. Petroleum exploration inherently involves very large uncertainties and demands policies that recognize that fact.

Let us envisage ten value estimates for a particular prospective block. Along comes an offer to furnish you with

one more. What would you pay to see the 11th estimate? Probably not much. For example, what kind of estimates would you get if the true value was about 1 million barrels (Figure 9)? We find eight estimates ranging from 130,000 barrels up to about 11 million barrels. None of them would give you much of a clue as to the truth. If the next estimate came in at 300,000, what more would you know? But some governments, not only go to the expense of making such calculations for themselves, in the case of the U.S., it will not award a tract if it thinks the parcel has higher value than the bid offered.

Royalty and Profit Sharing

Figure 10 shows host present value as a function of the royalty level. As with the chart on taxes, earlier, this one also uses a base of 100 million barrels at a 5% chance of success. The same result occurs. For a host that uses cash bonus bidding, no royalty yields a higher value to the host than zero! As before, we assume the bonus is invested in a portfolio of oil stocks and paid out over field life, as royalty would have been. Figure 11 illustrates the same point for profit sharing.

Concession Size and Length of Contract

Work commitment concessions tend to be much larger than the 5000 acre (~2000 hectare) tracts usually awarded through the U.S. leasing system. Switching to a full cash bonus system would probably alter those sizes. The size has to be large enough to capture a substantial portion of a prospective oil or gas field, but it need not cover multiple prospects. Since interested bidders will have had a chance to run seismic surveys, they will be able to narrow down the places of specific interest to them. Generally, the higher the costs and the more remote the area, the larger the concession should be, in order to allow for some economies of scale. The host would like to see as rapid and complete an exploration effort as possible. This would tend to drive the concession size down. Of course, the fact that an explorer/developer can purchase several adjacent tracts through sealed bid auction means size may not be the most important consideration. Experimentation by the host may be appropriate.

The more remote the concession, the longer the time necessary for exploration. Remoteness may not apply only to geographical considerations but also technological ones. In the Gulf of Mexico, for example, the U.S. awards ten year leases in deep water because the technology does not yet exist to economically produce some rather large discoveries.

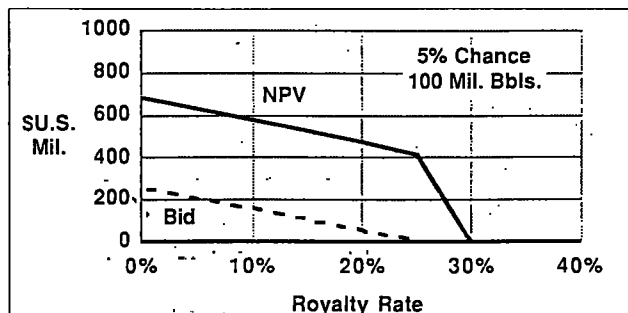


Figure 10: Host NPV and producer bid vs. royalty rate.

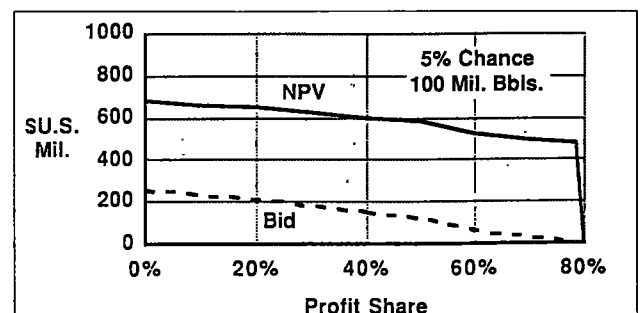


Figure 11: Host NPV and producer bid vs. profit share.

Less Developed Nations as Hosts

Less technologically developed nations may have higher borrowing costs. Remember, that we base the previous analysis on a host with a zero after tax and after inflation borrowing rate, along with a 6% after inflation investment rate. For a Third World nation with a borrowing rate of 4%+inflation, their present value also grows as they decrease the tax rate (Figure 12). But this is never as great as seen in Figure 6. The actual cash received, however, does not change unless costs to operate in the less industrialized countries differ from those in the more industrialized nations. Again there should be an incentive for all nations to reduce bureaucratic costs, since the nations themselves must bear the costs through reduced bonuses.

If a Third World nation had a borrowing rate of 6% or more, then it would still be better off with cash bonus and zero tax. It would simply opt to take the cash initially and dispense with the investment portfolio.

The full cash bonus truly is one size that fits all.

Reserves Lost Due to Taxes and Royalties

Another loss for the host because of taxes and royalties occurs when an investor-owned oil company walks away from a deal because the host share makes the proposal unattractive. Under a cash bonus system, that could never happen. Prospects that are barely economic will draw a small cash bid, and perhaps yield a discovery and development. Under typical contracts calling for taxes, etc., the property would never have been drilled in the first place.

How many projects fail to reach development because of this? It would be difficult to know. In Figure 13 the minimum economic field size given has a 53% tax. (I chose that rate because it approximates the combination tax, royalty, and carried interest of New Zealand.) Given a 3% chance of

success, it takes 100 million barrels to make the required rate of return and still pay all the bills demanded by the host. Were there no tax but just cash bonus bids, explorer/developers could afford to develop prospects as small as 60 million barrels. What proportion of prospects lies between 60 and 100 million barrels versus the proportion that lies above 100 million barrels.

We find the answer to that question by examining a field size distribution in a known area. I chose the Texas Gulf Coast onshore because there is much data available. To be a useful surrogate for other basins, the Texas Gulf Coast need not be a close geologic analogy. Figure 14 shows a cumulative distribution where 98% of the fields lie between 6000 barrels and 200 million barrels. The plotted points represent data while the straight line best fits that data in that it has the same mean and variance.

To get a clearer view, the upper end of the distribution is magnified (Figure 15). One hundred million barrels falls at the 96% point on the distribution and 60 million barrels lies on the 93% point. We want the proportion of fields between 60 and 100 million barrels compared to all fields over 60 million.

$$(96-93)/(100-93) = 3/7 = 43\%$$

Therefore, moving to a cash bonus system from the present one of taxes and royalties, will almost double the number of prospects drilled and perhaps increase the amount of oil and gas found by 30%. Actually, the ability of companies to estimate the reserve size prior to drilling is not very good, therefore, in practice the prospects where reserves are thought to be between 60 and 100 million barrels will be almost as good as those where the size supposedly falls above 100 million barrels. The host should benefit from additional exploration and production activity, jobs, and income. (The previous statements are based on the assumption that petroleum explorers will estimate about as many fields between 60 million barrels and 100 million barrels as they estimate over 100 million barrels.)

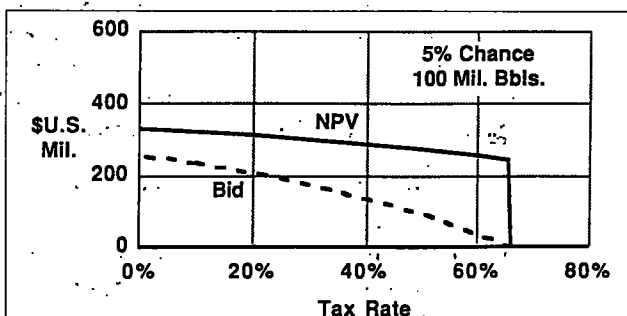


Figure 12: Developing nation NPV and producer bid vs. tax rate.

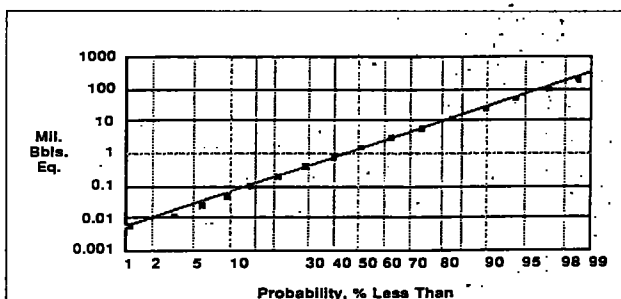


Figure 14: Texas Gulf Coast reserves through 1960.

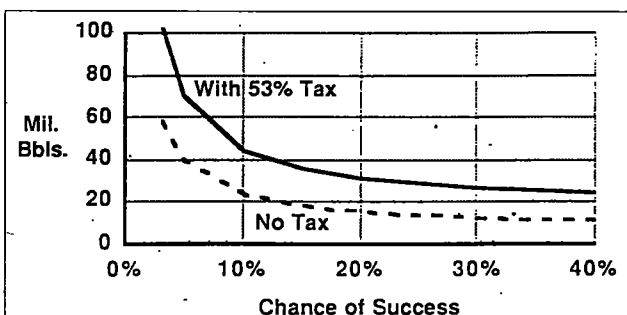


Figure 13: Minimum economic field size vs. chance of success.

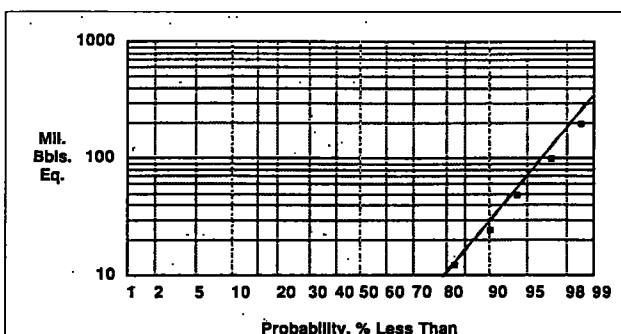


Figure 15: Texas Gulf Coast reserves through 1960.

Participation in Surprises

Given a cash bonus system, how does the host take advantage of future price increases should they occur? The simplest answer comes in the form of another question. Does the host also wish to take the risk of future price decreases? One could arrive at some sort of formula whereby the producer pays more to the host if the price of oil rises above a certain amount, for example, \$40/barrel. (All the economics in this paper assumed \$21/barrel.) Or the producer could get some credit if the price drops below some amount, let us say \$10. Such a rule would increase transaction costs and introduce complexity into the agreement. Generally, such complexity would reduce the cash bonus as bidders strive to protect themselves from the unknown. If the host decides that the adjustment shall be one sided, (i.e., the producer pays more if prices go up but gets nothing if prices go down) that would surely cause a lower cash bonus.

The idea of investing the cash into an oil company portfolio provides a no-transaction-cost protection for the host. If oil prices rise beyond general expectations, then the value of the portfolio rises. Of course general expectations would already be built into the cash bid, so the host is protected. If the host wants protection on the down side it could diversify its portfolio. Plenty of industries in the U.S. have done better than the oil industry - beverages, food, health care, pollution control, retail food stores, restaurants, and tobacco, to name a few.

Because of a quirk in the bidding process, the host may get the benefit of prices over and above general expectations. In any competitive process, those who believe in the greatest future value will tend to outbid others for the rights to the concession. That view of higher value may be due to one or a combination of optimistic estimates of the following items:

- oil or natural gas price;
- reserves;
- chance of success;
- facilities costs;
- producing rates; and
- operating costs.

Happily for the host, the high bidder may pay the host for a concession value based on \$30/barrel when in fact the price may never exceed \$25/barrel. Of course, bidders who understand such phenomenon can hedge their bids to counter it. They will not, however, hedge to such an extent that the host will not get at least fair expected value for its resources.

I cannot find the reference now, but some years ago there was a report from that part of the U.S. government that oversees oil and gas leasing in the waters surrounding the country. It said that the bonus paid through the years was equivalent to a very large royalty, about 70%. Now had there been a statutory royalty of 70%, companies would not have bid on the parcels at all because they would not have received a high enough return on their investment. But they gladly paid as much in bonus because they perceived that they were in control of their own destiny and that the return would in fact be sufficient.

What if nature fools everyone and provides a billion barrel field where no one thought there existed a potential for more than 100 million barrels. Dealing with events like these are among the hardest for a host. It does happen on occasion, and there is the tendency to claim the producer has unearned windfall profits that require special taxation.

Conveniently, everyone forgets all the times the explorer/producers overestimated reserves or drilled dry holes.

Big discoveries will ultimately work to the benefit of the host if it resists the inclination to impose a special tax. Call it the Las Vegas syndrome. Nothing pleases that Nevada gambling centre more than having a big winner every now and then. In fact the casino and city publicize the event so that the whole world may witness the good fortune of the lucky gambler. What a way to draw crowds! More and more gamblers show up hoping to hit the big one, and the casinos make more money than they would have otherwise.

Imagine the interest for the next lease sale in the vicinity of a large discovery. Competitors will come from all over to get in on the action. And more than likely, they will spend much more for the new concessions than they are worth. In 1969, the state of Alaska leased state lands in the vicinity of the 1968 Prudhoe Bay 10 billion barrel discovery. The properties brought the state almost \$1 billion dollars in cash, at a time when most people thought the future price of oil would be around \$3/barrel. Because of inflation in the U.S. since the time of that sale, that \$1 billion in today's dollars would be \$4 billion! Who remembers hearing about big discoveries on the concessions purchased at that sale?

Detractors

Not everyone will favour the arguments made in this paper. All over the world market economies have proven their worth, however, much opposition to them still exists. In most societies an elite contingent believes it can use command and control to make things come out correctly. It has been said, only half jokingly, that with the vast and monumental changes in the world over the last few years, the last bastions of command and control lie within Cuba and the U.S. Department of Energy. A market economy has little use for elitists; the feeling is mutual.

Some reviewers have criticized this work because it makes values appear through use of different discount rates between the buyer and seller. My reply is that nothing so characterizes the market system as different value beliefs between buyers and sellers. Discount rate merely provides one of the manifestations of those differences.

Some explorer/producers may not agree with the ideas presented in this paper. Many business people believe in the trials of the market place for everyone else, but want a special deal for themselves. We will always see people trying to make those special deals, hoping to gain some advantage over their competitors.

Small companies may think they cannot keep up with the large companies in a cash bonus game. Again, apparently sound logic falls for want of supporting data. Some years ago the U.S. government let itself be pressured by small companies into rules that "level the playing field". The largest companies were not allowed to bid in partnerships with each other, because their financial strength would force everyone else out of the sale, or so went the argument. Those with the money buy all the prime areas and make all the money. However, looking at earlier charts (Figures 8 and 9) recall that no one knows in advance exactly where the good blocks are.

Using government production and cost data gathered from all the operators in the Gulf of Mexico, Mead and others (1983) found (as government analysts had found

earlier) that small companies actually made a higher return than the larger ones. Companies with more financial resources did tend to buy what was generally considered the best blocks, but the competition for the blocks was so tough that these companies overbid and ended up with lacklustre returns. And remember the uncertainty? The smaller companies were left picking up the crumbs—like the flank blocks relative to the more popular crestal blocks. But capricious nature does not always play by gentlemen's rules. More often than not, the mineral treasure is scattered down into the flanks. Not only did the companies without big financial backing make significant discoveries, but, they ended up

paying much less for them, and so made a higher rate of return than their more wealthy opponents.

Conclusions

The conclusions reached in this paper are made from observation of the way things work, especially with regard to competitive processes. It seems clear that for any resource owner, there will be advantages in putting the competitive market to work on evaluating and developing the resources. Not so strangely for believers in the market, a process that maximizes the profit to the resource owner also maximizes the opportunity for the explorer/producer. Such is the way of the market place; it only works because both sides win.

Reference

MEAD, MOSEIDJORD, AND SORENSEN, 1983: The Rate of Return Earned by Lessees under Cash Bonus Bidding for OCS Oil and Gas Leases, *The Energy Journal*, Vol. 4, No. 4.

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ED CAPEN wrote this paper when employed as a Distinguished Management Advisor for ARCO. He retired shortly after its presentation. He was with Atlantic Richfield for almost 35 years beginning as a research physicist in the company's Dallas, Texas laboratories. He strayed from geophysics to pursue interests in economics, competitive bidding, risk assessments and financial management. Recently, he has concentrated on helping people to see a wider array of alternatives prior to making decisions. He has twice been named a Distinguished Lecturer for the Society of Petroleum Engineers, in 1974 and again in 1987. In 1989, he received the J.J. Arps Award from the Society of Petroleum Engineers for significant contributions to the field of petroleum evaluation. One of his more popular papers (co authored with Clapp and Campbell) entitled *Competitive Bidding in High Risk Situations* appeared in the *Journal of Petroleum Technology* (June 1971), and first introduced the term "winner's curse" to the literature of bidding. In May of this year, Mr Capen made his first visit to New Zealand and gave a seminar on exploration uncertainties and economics to a group from the Ministry of Commerce.