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IMPACT OF INCREASED TAXATION ON OIL EXPLORATION
AND DEVELOPMENT IN ALASKA

A Report to the
Alaska State Legislature

March 25, 1977

Tanzer Economic Associates, Inc.



POUCH V
JUNEAU, ALASKA 99811

Alaska State Legislature House of Representatives

24 March 1977

All Members
Alaska State Legislature
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Juneau, Alaska 99811

Enclosed is a report entitled Impact of Increased Taxation on Oil Exploration and Development in Alaska, the second report prepared by Tanzer Economic Associates, Inc., of New York, pursuant to a contract with Legislative Affairs Agency.

This report includes three areas related to oil taxation in Alaska. They are (a) the historical experience, (b) an update to the prior document, Alaska Prudhoe Bay Oil: Profitability and Taxation Potential, prepared for the Second Session, Ninth Alaska Legislature, dealing with the profitability of oil production in the Sadlerochit formation by Sohio/BP, ARCO, and Exxon, and (c) the benefits and costs to Alaska from increased oil taxation.

Very truly yours,

A handwritten signature in cursive script that reads "Hugh Malone".

Hugh Malone
Speaker

HM:jb

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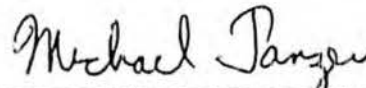
February 3, 1977

Representative Hugh Malone
Vice-Chairman
Subcommittee on Oil and Gas
Leasing and Tax Policies
Alaska State Legislature
Juneau, Alaska 99811

Dear Sir:

I have the honor to transmit to you the attached report on "Impact of Increased Taxation on Oil Exploration and Development in Alaska." This report was prepared under contract with the Legislative Affairs Agency of the Alaska State Legislature.

Yours sincerely,



Dr. Michael Tanzer,
President

MT:lah

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SUMMARY

The purpose of this Study was to analyze the possible impact of increased State oil taxation on oil exploration and development in Alaska. The background for the Study was the dire warnings of the oil companies that substantially increased State taxes will hurt their future efforts in Alaska. To help assess these claims, three different approaches were taken.

First, an examination was made of a variety of historical cases in which major oil tax changes have been proposed or carried out, focusing on the impact on the countries involved, including the reactions of the oil companies. Second, the likely profitability of Prudhoe Bay crude oil under various tax assumptions was reassessed, and this was compared with the companies' tax and profitability prospects in other producing areas which might be competitive with Alaska. Third, an analysis was made of what the costs and benefits of increased taxation might be for the State of Alaska, in terms of possible reduced exploration and development versus increased tax revenues from Prudhoe Bay alone.

In the first part, the Study examined the experience of oil tax increases in Iran in the 1950s, Venezuela in the 1960s, and Indonesia, Malaysia, the United Kingdom, Norway, the Netherlands, West Germany and New Zealand in the post-1973 period.

It was shown that there is no simple pattern of oil company reaction to such changes as regards oil production, exploration and development. Moreover, it was argued that this is not surprising since many other factors besides a change in tax rates affect the companies' incentives. The one commonality in these cases, however, was that government attempts to increase oil taxes almost invariably brought forth company reactions that this will be harmful to the country. The Study therefore concluded that while such "warnings" are normal forms of company "propaganda", they need to be taken with a large grain of salt, and the specifics of each situation carefully analyzed.

Towards this end, in the second approach the Study first reassessed the profitability of Prudhoe Bay oil originally made in the "Tanzer Report". The reassessment was based on conservative production and investment estimates made by a New York brokerage firm, for the most probable oil price, \$13 per barrel in Los Angeles. Three State oil tax cases were considered: the present State tax structure; a "50% State take" case where Alaska gets (including royalty and severance) 50% of the oil pie; and a 50% State income tax case (in addition to royalty and severance). The analyses showed that under the present State tax structure the companies' DCF profit rate would be 29% per year, while even with a 50% State income tax it would be 19% per year (with a 23% profit rate for the intermediate 50% State take case). The companies' per barrel profits (and their percentage share of the oil pie) were estimated as

follows: present tax structure, \$2.70 (37%); 50% State take, \$1.80 (25%); and 50% State income tax, \$1.40 (19%).

Oil company profitability and taxation policy in other major oil producing areas were then analyzed to assess Alaska's competitive position. It was shown that generally company profits elsewhere were much less than in Alaska, even under the highest State income tax rate considered. In the OPEC countries of the Middle East, North Africa and Venezuela, the companies' profits amount to about 15 to 30 cents per barrel, giving them only 2% of the oil pie, with 98% for the governments. In Indonesia, which allows the highest profit among OPEC members, \$1.00 to \$1.50 per barrel, the companies get about 12% of the oil pie and the Government 88%.

Outside of the OPEC countries, in Canada the companies get about \$1.25 per barrel, or 11% of the oil pie, which is less than they would get from Prudhoe Bay under a 50% State income tax. Even in the North Sea, where it is estimated the companies will get about \$3.50 per barrel, this is shown to be related to the very large investment costs there, which are twice as great as in Prudhoe Bay; on a DCF basis the companies' North Sea profit rate is estimated at 19% per year, or about the same as for Prudhoe Bay with a 50% State income tax.

The Study also discussed Alaska's other advantages to the companies. The fact that in a world of crude oil scarcity assured supplies are becoming increasingly vital to the companies to protect their refining and marketing investments makes the

possession of U.S. oil particularly valuable to them. This is reinforced by the trend toward 100% nationalization by OPEC members and "participation" by governments in the North Sea (and even Canada). In the light of all these factors, it was concluded that substantial increased State oil taxation is not likely to end the attractiveness of Alaska to the oil companies as a place for additional exploration and development.

Finally, in a third approach, on the hypothetical assumption that the latter conclusion is wrong, the Study tried to assess the benefits and costs to Alaska from increased oil taxation. The benefits would be the direct ones of a total of \$15 to \$21 billion in increased State revenues from the main Prudhoe Bay formation alone (or \$750 million to \$1,100 million per year). The indirect benefits would be the potential "multiplier" effects on economic development, since the increased taxes would stay within the state rather than be exported as oil company profits and federal taxes. The "costs" would be whatever exploration and development were cut off by the increased tax rates. The Study estimated that for the most critical function, exploration, the increased revenues could likely pay for any such losses; for the much larger development effort, once oil is found financing is readily available. (It was also noted that since the State has a lower cost of capital than the oil companies' target profit rates, more development of marginal oil fields might take place if the State participates than if development were left solely to the companies.) The overall

conclusion was that the benefits of increased State taxation are clear and very large while the costs are unclear and likely to be much less sizeable.

In an afterword to the Study, an overall strategy for State oil policy was discussed. It was suggested that the State should substantially increase its tax rates; it should temporarily cease leasing its potential oil-bearing lands; it should invest some of the increased tax revenues in a complete exploratory survey of its lands; and following such a preliminary inventory of potential, it should either directly contract for further exploration or work with oil companies on a joint venture basis. While this might not lead initially to the fastest possible pace of oil resource development, it was shown that other oil producers like Alberta, Canada and Norway have from their experience become wary of too rapid oil resource development.

IMPACT OF INCREASED TAXATION ON OIL EXPLORATION
AND DEVELOPMENT IN ALASKA

I. INTRODUCTION

Consideration by the Alaska State Legislature in the last session of increased taxation on oil profits has brought forth numerous dire warnings from the oil companies that such measures will make Alaska "unattractive" as a place for future oil exploration and development. As The Anchorage Times reported in January, 1976, with regard to a proposed "excess profits tax", "leaders of the oil industry appear to be just as certain that the tax would throttle further interest in Alaska exploration. Investment funds would no longer be available here because they could be used more profitably elsewhere."¹ More recently, this theme was reiterated by a Vice President of Sohio, who spoke in Anchorage of a modern version of the fable of "the little red hen" which makes all the bread "without the benefit of other barnyard dwellers--who are standing ready to charge 'excess profits' and help consume the finished loaves."²

Given this background, the aim of the present study is to attempt an objective assessment of the likely impact of increased State taxes on future oil exploration and development in Alaska. The study is divided into three parts. The first (Chapter II) examines a variety of historical cases in

which major tax changes have been proposed or carried out, focusing on the impact on the countries involved, including the reactions of the oil companies. The second part (Chapter III) analyzes the comparative tax position of other countries and states today, and the resulting profitability of crude oil production which might be competitive with Alaskan oil. The concluding part (Chapter IV) deals with what the costs and benefits of increased taxation might be for the state of Alaska, in terms of possible reduced exploration and development versus increased tax revenues from existing oil fields.

II. HISTORICAL EXPERIENCE OF GOVERNMENTAL CHANGES IN OIL TAX RATES

In this chapter we make no pretense of presenting a complete analysis of all the historic experiences of governmental changes in oil tax rates. The oil industry is so widespread and has such a long history of acrimonious tax disputes that a complete analysis would be far beyond the resources available for the present study. Instead, after an examination of some of the available literature, we chose a few examples from the post-World War II period prior to the October 1973 jump in oil prices, and several others from more recent experience. We believe that this sample, while not definitive, is illustrative of the kinds of reactions which have taken place in this highly controversial area.

By way of introduction, it should be noted that, by its nature, the question of the impact of tax changes on oil company behavior is a very difficult one for the outside observer to answer. Many factors besides the level of government taxation can affect the willingness of oil companies to invest in exploration and development or to produce oil in any given state or country. Among the most important of these other factors are the chances of finding sizable amounts of oil, the expected finding and development costs, the individual company reserves and costs of production from these existing reserves, and the

comparative tax rates and potential profitability in other states and countries where oil might be sought or produced; for some of these factors the outsider has little if any information.

Thus, it may well be that where a government seeks to raise oil tax rates to such a level that it appears less profitable to the oil companies to explore and develop or produce in that country than in other prospective areas, the changed tax rates can be decisive in reducing exploration or production. On the other hand, in examining a particular case, it may also be the fact that increased taxes are associated with declining exploration or production, but are not the real causes; just as we can find cases where increased taxation is historically associated with increased production, but again other factors are operative. Hence, to truly estimate the impact of increased taxes in any particular case, one must examine the specific context in great detail.

Nevertheless, as we think the following sample of cases will show, while increased taxes may or may not be the cause of declining exploration and development or production, there is one effect almost invariably caused by such tax changes. Namely, an almost automatic reaction of the oil companies to claim that such increased taxation will force them to look elsewhere for increased future production. These claims are sometimes backed up by actions, aimed at getting the country to rescind the tax increase, such as temporarily cutting present

production or reducing exploration and development efforts. Thus, while the struggle between the oil companies and the governments over increased taxation is a deadly serious matter involving huge sums, it is helpful to recognize that some of the actions and much of the rhetoric (on both sides) is "theater", aimed at improving a bargaining position, and often needs to be taken with a very large grain of salt.

A. Major Oil Tax Changes Prior To October 1973

Perhaps one of the most dramatic confrontations over attempted tax increases took place in Iran in the early 1950s, between the Government and British Petroleum (at that time named the Anglo-Iranian Oil Company). The background to this tax confrontation was that up to 1948 the division of oil profits in Iran between BP (which had a virtual monopoly of Iran's oil resources) and the Government was about 83:17 (in favor of BP).¹ The Iranian Government sought a higher royalty rate and a more favorable division of income, and after prolonged negotiation in 1949 BP agreed to a roughly 70:30 split (still in its favor).² However, by that time the principle of a 50:50 split had been established in Venezuela, and it soon spread to Saudi Arabia and the rest of the Middle East. Despite this, BP refused to budge, and its intransigence led to the complete nationalization of its Iranian oil holdings by the Mossadegh Government in 1951.

Several steps in this sequence are instructive. First, at the height of the 1951 dispute, Iran's Ambassador in London explained the view of his Government in an official statement:

. . . Persia [the name for Iran at that time] has not, by any standards, received a fair and reasonable share of her vast oil resources Repeated attempts on the part of Persia in the last few years to obtain a just share of the oil profits, and an honourable and equitable part in the control and administration of this vital concern to Persia, have not met with that spirit of partnership and far-sighted co-operation so essential to the smooth working of a national enterprise of this calibre.³

While BP refused to improve its offer to the Government, and Iran began to move towards nationalization, the company made no public statement about the reasons for its unwillingness to improve on the 70:30 profit split. But the United States Ambassador to Iran at that time, Henry Grady, later explained what, in his view, was happening:

The company [BP] said, "No, we will make no further concessions." The point of view of the company was that if they made any concessions, that would be a show of weakness [Their] slogan was, "When they need the money bad enough, they will ratify." Well, I happen to know--I knew it from many sources--that that was the slogan. The theory was: they'll have to accept because they need these royalties to carry on--and they do. That was their position. I call that a semi-colonial, at least --if not colonial--point of view.⁴

Second, despite BP's view that Iran would have to give in, it did not, and even a Western boycott of Iranian oil after the nationalization, which virtually ended her exports of oil, failed to bring the country to its knees. Only a coup, organized by the U.S. Central Intelligence Agency, finally overthrew the Mossadegh Government in 1954 and forced the denationalization of Iranian oil.⁵ Ironically, as part of the new order, BP was forced to share the oil with a number of other companies, primarily from the United States, and retained only 40% of the concession.⁶ Moreover, the new consortium which was formed gave the Iranian Government the same 50:50 profit split that BP had originally refused and which led to its nationalization.

Finally, despite this sharp oil tax increase, Iranian production then rose rapidly. Thus, by 1957 it had passed the

1950 peak, and in the next six years it more than doubled; by 1970 total production was six times as great as the pre-nationalization peak.⁷ The basic reason, of course, for this rapid growth was that the cost of production of Iranian crude oil, like that of most of the Middle East, was relatively low, and its tax rates were no higher than the other major Middle Eastern producing countries, all of which enjoyed rapid growth in production after World War II.

A second interesting historic tax change case is that of Venezuela in 1966, when the Government was seeking to increase its share of oil profits. The background here was that during the 1960s oil prices were generally falling, and the argument was made that such a tax increase would hurt the country rather than help it. As Petroleum Intelligence Weekly (PIW), an authoritative oil industry trade journal, stated at that time:

If Venezuela pushes the new reference price system through, it could basically alter the current competitive position of Venezuelan oil vis-a-vis oil from North Africa and the Middle East, oil circles note. One observer summed it up this way: "If Venezuela establishes a tax price higher than the current realizations, this will merely raise the cost of Venezuelan oil to the companies. . . . With higher cost through the new tax system, Venezuelan oil will be that much less competitive, production will decline, new oil investment will shrink to zero and the country will continue to lose position in world wide markets."⁸

Again, Exxon, the principal producer in Venezuela (through its subsidiary, Creole Petroleum) gave similar warnings in an attempt to ward off the increased taxes:

The reasons why Venezuelan crude oil is increasingly unable to compete for markets with crude from the Middle East were starkly outlined by Esso's subsidiary, Creole Petroleum, in a paper recently presented to the Venezuelan congress and subsequently released to the press by congressmen. Venezuelan crude production, stagnating over the past years in relation to the Middle East, is actually down 2.8% below 1965 levels so far this year.

This decline, coupled with the Venezuelan government avowed goal of increasing taxes on oil, has resulted in what may be described as a national debate on the future of the oil industry in that country. No final decision has been reached on new taxes to date. But Creole in its document marshals facts to support its argument that additional taxes will only cripple an industry already handicapped in maintaining market outlets.⁹

Despite the warnings, the Venezuelan Government persevered and negotiated a settlement which involved roughly a 5 percentage point increase in its share of oil profits, from 67% to 72%.¹⁰ After this change, again according to PIW:

The big question remaining in Venezuela: Whether production will start going up now that the settlement has been achieved. The question is critical for Venezuela because a slowdown in output, of course, would reduce the government's income. The Minister told the nation that production could be expected to rise between 3% and 4% annually over the next five years. But oil companies point out that they have given no guarantees on production levels. And in view of this year's experience (output is down some 3.55% below the same period a year ago), it's not certain that output in the future will even remain at current levels.¹¹

In fact, production did increase gradually in the next five years, although the rate of increase was about half that predicted by the Venezuelan Government.¹² Here again, the basic reason would seem to be the competitive advantage enjoyed by the very low cost of production of Middle Eastern crude oils.

After the settlement was reached, a columnist for PIW

was refreshingly candid in his statement about oil company tactics for warding off tax increases:

Every time Venezuela has changed its taxation structure, there have been prophets of doom who have forecast the waning of the country as an important oil producer. In 1958, when the last major tax change was made, the oil companies made repeated approaches to the government that could almost be described as alarmist in depicting the dire results that the tax measures then proposed could produce.¹³

(With regard to the observations about the company reaction to the 1958 tax increases, it might also be noted that during the 1959-65 period Venezuelan production increased by about 25%, in line with the Government's general goal of moderate annual increases.¹⁴)

Finally, it is also interesting to note the role of local private industry in this oil policy debate, as reported by PIW prior to the settlement:

A slashing wide-ranging criticism of Venezuela's petroleum policy has just been presented here by Fedecamaras, a nationwide organization representing most private sectors of the country's economy....

Fedecamaras points out that Venezuela may have to lower production goals during the next decade because a drastic reduction in investment is causing a cutback in exploration....

The major premise behind the government's oil policy--that over the long term oil will become scarcer, and hence prices will improve--is false, according to Fedecamaras.

. . . The study says the government theory is that once the present unbalanced supply-demand situation is past, prices will rise substantially.

Therefore, Fedecamaras contends, the government sees every barrel of oil not produced now being worth more in the future. Consequently, the government strives for the highest possible price per barrel at present, even at the expense of losing production and markets.¹⁵

While this question of whether it is better to leave the oil in the ground than to produce it will be dealt with later, it is an ironic footnote to this episode that, at the time this Venezuelan industry group was attacking its Government for its "false" premise that in the long term oil prices will improve, the price of oil exported by Venezuela was under \$2 per barrel!¹⁶

B. Some Oil Tax Changes After October 1973

Turning to more recent cases, a dramatic example is the long tax change struggle which is still taking place in Indonesia. In January 1976 the Indonesian government announced it wanted to increase its share of the oil profit split with the companies from 65:35 in its favor to 85:15. Up until that time Indonesia had been highly regarded by the oil companies, as this early 1975 analysis by The Petroleum Economist, an industry trade journal, indicates:

One of the happier recent reversals in the oil world has been the cordial and profitable relations the industry now enjoys with Indonesia, compared to the tensions of the middle 1960s, the closing years of Sukarno's government. The credit is in general due to the western-alliance policies of President Suharto, Sukarno's successor from 1967, but more specifically to the pragmatism of Dr. Ibnu Sutowo, a leading Indonesian state oil official from 1957, and head of the state oil company Pertamina from its inception in 1968. His ambition has been to build an integrated company with full control of the nation's oil industry, employing foreign contractors, yet allowing them a good profit.¹

The quantitative background to this struggle was that Indonesia, although a member of OPEC, was obtaining only a 65:35 profit split, at a time when most other OPEC members were getting a division closer to 95:5 or more; this meant that the oil companies in Indonesia were reaping per barrel profits of \$2.25-\$2.50, compared to only 25-50 cents in the Middle East and Venezuela. (See Chapter III.)

Nevertheless, Indonesia's announcement of the proposed tax increase of about \$1 per barrel, which would still have

left the main producers there, Caltex (Standard of California and Texaco) and Standard Vacuum (Exxon and Mobil) with per barrel profits of about \$1.25-\$1.50, brought forth company warnings. PIW reported in March 1976 "the oil producing companies' contention that a sharp hike in government 'take' would force production cuts, reduce overall revenues and discourage future investment."²

Additionally, Caltex also argued that its high profits on Indonesian oil were necessary because it had to subsidize losses on its sales to refineries. And, if the producing profits were cut, it might be forced to drop its Indonesian production to as low as 700 thousand barrels per day, from its 1975 average of 831 thousand barrels per day. Hence, this would mean the tax increases would cause a net loss in oil revenues for the Indonesian government.³ Leaving aside the factual question as to whether Caltex really does lose money on its sales of crude oil, it only takes a little calculation to see that from the Indonesian Government viewpoint this loss of revenue argument is of dubious weight. It is true that if production fell by the maximum amount predicted, then with increased tax rates the government's revenue would fall, from about \$3,000 million to \$2,800 million. But, note that this temporary loss of \$200 million in government revenues would allow the country to keep in the ground some 48 million barrels of oil. With the new government take of \$11 per barrel this would mean additional potential future government revenue

of about \$520 million. Thus, while the country would forego a maximum of \$200 million in immediate income, over the longer run it would save a net amount over \$300 million.

In any event, despite Caltex's arguments, and after negotiations failed to reach agreement, in April 1976 the Indonesian government imposed the tax increase of about \$1 per barrel on Caltex and Standard Vacuum, which were working under old "contract of work" agreements. The government then turned to the smaller companies which were working on newer-type "production sharing" agreements. Here the government proposed not only to increase its share of the profit to 85%, but also to stretch out the period in which the companies were allowed to recover their costs (they had been allowed up to 40% of all oil production each year for cost recovery). The reaction of this group of companies, according to PIW, was as follows: "No matter what specific cost recovery proposals are finally enacted, the companies are pretty much unanimous that abolition of the speedy payback under the 40% ceiling will slow down exploration and could even make development of some recent discoveries uneconomic."⁴ Despite these "warnings" the Indonesian government pushed through the changes, which both slowed down the companies' cash flow and reduced their profits by an average of \$.30 to \$1.00 per barrel.⁵

It is probably too soon to tell the effect of these various changes on the prospects for development of Indonesian oil production. On one hand we do know that Caltex's warning

of a sharp drop in its oil production in 1976 failed to materialize, and its production for the year was about the same as in 1975.⁶ As for the smaller companies, their output in 1976 increased by over 30%, at a time when world oil production was basically stagnant.⁷

On the other hand, as of today, exploration drilling in Indonesia has come to a virtual standstill as the companies seek some changes in the tax laws.⁸ Whether this is a permanent drop, or simply part of the war of nerves with the Indonesian government over the tax changes, or partly due to other factors, remains to be seen.⁹ What is clear, however, is that, owing to the per barrel tax increases, Indonesia will have increased its tax take by at least \$500 million in 1976 alone. Such a sum could finance a large amount of exploration and development efforts for the country (which, for example, might be carried out with drilling companies working under direct contract for the Government). Thus, even while the tax changes may have had some negative impact on the companies' current exploration and development efforts, much of this could be offset from the increased tax revenues.

This can be seen from the fact that in 1975 total exploration and development expenditure in Indonesia was about \$1.0 billion, and before the tax dispute a similar expenditure had been planned for 1976.¹⁰ Moreover, based on data which indicate that less than one-third of the wells being drilled in Indonesia are for exploration, it would appear

that the Government's \$500 million increase in tax revenues could pay for the total exploration effort in the country.¹¹ (Since this point has more general implications, it will be examined in greater detail in Chapter IV when we discuss the alternatives open to the State of Alaska.)

Finally, Indonesia's future prospects need to be seen within the context of a general worldwide trend for governments to capture part of the windfall profits arising from OPEC's price increases. The trend began with the OPEC countries themselves, who after the sharp price increases in 1973 also sharply raised their tax rates on the companies. Typically, what had been in mid-1973 a government:company profit split of about 65:35 was raised ultimately to 95:5 or more.¹²

But, even in the industrialized countries with sizable crude oil production prospects, parallel if not so sweeping changes took place. In late 1974 and early 1975 Norway and the United Kingdom both proposed substantial "windfall profits" taxes (as well as plans for direct Governmental "participation" in the oil industry), which after some revisions were subsequently adopted. (See Chapter III.) Moreover, these proposed changes brought forth the usual warnings from the oil companies and their trade journals. For example, The Petroleum Economist in January 1975 lamented:

The spirit of OPEC, which aims at ever-increasing per-barrel revenues and maximum state participation and control, has now firmly taken hold of the governments surrounding the North Sea. The only North Sea countries as yet unaffected by this spirit are Denmark and West Germany, where petroleum exploration to date has not unlocked big offshore reserves. . . .

. . . The Dutch government had already stated in autumn 1974 its intention to seek a more than 80 per cent share in the profits of all oil and gas exploitation, by means of 40 percent participation, royalties and taxes

The enthusiasm of oil companies for exploration in the North Sea is steadily waning as government penalties for success increase.¹³

To add insult to injury, in May 1976 the Dutch Government announced new rules for future oil licenses in its sector of the North Sea. Among other things, new terms provided that the State would have the right to own 50% of all oil and gas found (up from the previous terms of 40%, for gas alone) and also would get 70% of the companies' net profits (up from 50%). Not surprisingly, "the higher taxes have already caused the chairman of the organisation of exploration companies, Nogepe, to warn of the possibility that companies may give up the idea of future operations offshore."¹⁴

Despite all these "warnings", North Sea exploration prospects appear to be quite bright. Thus, for example, a recent analysis by a British petroleum consulting firm (which was implicitly "warning" against even further increases in taxes) estimated that under current tax conditions as much new reserves would be found offshore Northwest Europe in the next 10 years as had already been found, much of it in the North Sea.¹⁵

To round out the European picture, even West Germany, which has a small domestic oil production industry (production of about 150 thousand barrels per day) in early 1976 was considering a "windfall profits" tax on its oil and gas

production.¹⁶ According to industry sources, the size of the additional tax increase was in the neighborhood of about \$114 million, or 1.2% of total oil and gas revenues.¹⁷ However, consideration of the Federal Government tax was put off because of strong opposition from the two principal oil producing States in West Germany which "charged the tax would threaten local oil investment and employment, state income tax "take" from oil companies, and any chance of raising state royalties."³

Interestingly, the big oil companies in Germany were divided over the tax increase issue. Exxon, a leading crude oil producer in Germany, was opposed to it. BP's German affiliate, Deutsche BP, however, which is primarily a refiner in Germany, favored the windfall profits tax, as a way of reducing the competitive advantage of the companies like Exxon which had crude production in Germany. (BP even favored coupling the new tax with a crude oil cost equalization program, analogous to that in the U.S.)¹⁹

Finally, we might note that Indonesia's tax increase apparently helped stimulate its neighbor, Malaysia, to increase its share of oil profits. The Malaysian government too had been getting a 65:35 split with its oil companies (Exxon and Royal Dutch Shell), but after negotiations and much pressure on both sides, at the end of last year the government share was increased to somewhere between 83% and 89%.²⁰ Despite this large increase in taxes, Platt's Oilgram News Service (an industry daily)

headlined its report: "Exxon, Shell optimistic on Malaysia operations under revised contracts".²¹ Platt's further noted that while Exxon now claimed it would cut its original production target from 30,000 barrels per day to 20,000 barrels per day, Shell "said its new contract (still to be signed) would provide sufficient incentives for the company to continue a high level of activity, including a reasonable level of exploration"; 50 companies are now interested in exploration.²²

By way of conclusion of this historical survey, it is not our claim that governments can at all times increase their tax shares without limit. As an example, we may take the case of New Zealand, which in October 1976 sought to impose a \$3 per barrel "energy resources tax" on crude oil production. According to Platt's, "company spokesmen say the levy, coming on top of the recent policy of letting the companies bear the brunt of all exploration costs while giving up a 51% stake to the government in the event of a find, will bring new exploration activity in New Zealand to a complete halt."²³ Following this warning, an important exploration company in New Zealand, Hunt International Petroleum, then discontinued its efforts and said it would seek \$100 million in "compensation" from the government for past exploration efforts.²⁴

Faced with this heavy pressure the Government quickly dropped its tax proposal: "instead, the Prime Minister announced, it will work out a profits tax and discuss the basis for it with exploration firms with an eye to making it

effective next April."²⁵ Perhaps at that time it will be possible to judge whether the New Zealand Government did "overreach" and seek an uneconomic level of taxes, or instead simply was not in a strong enough position to resist the counter-attack of the companies. That the clash between the companies and the Government, however, was fierce, can be seen from Platt's report last November:

The following exchange reflects the bitterness of the discussions that developed over the proposed levy between [Prime Minister] Muldoon and the exploration companies:

Muldoon said publicly that Hunt International Petroleum's "general approach to these questions is to the right of Ghengis Khan." John Tatum, New Zealand general manager for Hunt, which had suspended exploration, responded saying, "When you deal with Atilla The Hun, you don't send Snow White."²⁶

Finally, it may be observed that the single commonality among all the cases we have examined is that government attempts to increase oil taxes almost invariably bring forth company reactions that such tax changes will be harmful to the country. This should not be surprising, since like any small self-interest group which seeks to win public support, the oil companies' appeal must be to the interests of the general public rather than to their own primary concern--reduction of their profits. Furthermore, it must be recognized that such appeals, which are designed to influence official and public opinion to drop or modify the tax changes, are perfectly legal forms of "propaganda". On the other hand, it should also be recognized that there is nothing sacred about the content of

these propaganda appeals, as they may or may not reflect the reality of a given situation.

Given this context, it is extremely important in attempting to evaluate the possible impact of a government tax change on oil production or exploration or development to do two things. First, to attempt to see how the changed tax rates would affect the oil companies profit prospects not just in absolute terms, but also in relation to their alternatives in the rest of the world. And second, for any possible tax changes, to estimate the benefit-cost ratio to the government, derived from weighing possible gains in present and future government revenues against possible losses from reduced present or future exploration or production. It is to this first task that we turn in the next chapter.

III. OIL COMPANY PROFITABILITY:

ALASKA AND ELSEWHERE

In assessing the impact of possible Alaskan tax changes on the oil companies' production or exploration and development plans, it is important to know not only the companies' likely profits after these tax changes, but also how these profits compare with the companies' alternatives in other places. In the "Tanzer Report", while the focus was on likely company profitability in Prudhoe Bay, a few estimates were made of oil company profits elsewhere, based on data available at that time.¹ Since a year has now passed during which there have been a number of price and tax changes in the rest of the world, and additional data has become available, in this Chapter we take an updated and expanded look at the comparative profit picture.

A. Oil Company Profitability from Prudhoe Bay: A Reassessment

To start with, we need to estimate again the likely oil company profitability in Prudhoe Bay, under different tax assumptions. To do this, we have updated the analysis of the Tanzer Report to take new data into account. Moreover, to be on the conservative side, we have adopted many of the estimates made in April 1976 by Drexel Burnham and Company (DB), a New York brokerage house which can hardly be accused of being hostile to the oil companies.¹ The specific changes are as follows.

First, we have increased the estimated investment in Prudhoe Bay, based on company estimates reported by DB. According to the DB study, Arco data now indicate an estimated total investment in Prudhoe Bay over the life of the field at about \$7.2 billion, while Sohio data indicate a lower total investment of about \$4.5-\$5.1 billion. Since our original report used a figure of about \$4.6 billion, to be on the conservative side we have now adopted the higher Arco estimates.² Second, the DB study, which also uses the higher Arco estimates, also presents estimated annual depreciation figures for the years through 1990. Since our original annual depreciation estimates were a rough average, and based on the lower investment figures, for consistency we have adopted the DB depreciation estimates.³

Third, we have used the lower production schedule estimated by DB (with peak production of 1.5 million barrels per

day versus 1.6 million barrels per day in our report).⁴ Related to this, we have adopted DB's estimated pipeline tariffs based on the lower production schedule; this increases the average tariff to about \$4.50 per barrel with peak production, versus about \$3 per barrel in our original report. Finally, we have used DB's estimated operating costs of \$.25 per barrel and marine transport costs of \$.50 per barrel (which are slightly lower than our earlier estimates).⁵

On the other hand, our treatment of the tax question has remained basically the same, and is somewhat different than that of DB. Thus DB uses a 48% federal income tax rate on net income, but does not provide data on annual company income tax credits for the years up through 1977, before Prudhoe Bay production begins.⁶ We, therefore, estimate such annual income tax credits for the 1968-77 period, as in our original report, by applying an estimated 25% discount to the annual investment base in that period.⁷ Moreover, DB assumes for its present tax case that the nominal 9.4% state income tax rate will be effectively realized by the State of Alaska. We, however, assume an effective income tax rate of only about 2.5% per year, which number is derived from data recently provided by Sohio to the State of Alaska.⁸ (Finally, to again lean on the conservative side, we accept DB's assumption that in the future the companies will no longer be allowed to "expense" intangible drilling costs.⁹)

To reassess the impact of possible State of Alaska oil

tax rate changes on company profitability, in this study we look at two arbitrarily chosen cases to compare with the present tax situation. The high case is one in which the State of Alaska levies a 50% income tax rate on oil company profits (the "50% State income tax case", as in our original report). The intermediate case is one where an income tax is levied such that the State's share of the total "oil pie" (defined as wellhead value less depreciation less operating costs), including royalty, severance and other oil field taxes, is 50% (the "50% State take" case); with royalty and severance at about 20% of wellhead value, this implies an effective State income tax rate of about one-third on oil company profits.¹⁰

Then, using the DB data and our methodology as indicated, we analyzed the most likely price case--\$13 per barrel for Alaskan crude oil delivered in Los Angeles. (The uncertain impact of a possible crude oil surplus on the U.S. West Coast was ignored, in part because the DB study concludes that it is not likely to have a significant effect on the Alaskan wellhead value.¹¹) The results were as follows.

For the present State tax structure, and with an effective federal income tax rate of 48%, the companies' DCF rate of return would be 29% per year (as compared to our original estimate of 35% per year); the division of the oil pie would be 37% for the companies, 35% for the federal government, 3% for other states and 25% for the State of Alaska (in line with our

original estimates). At the other extreme, with a 50% state income tax rate, the companies DCF return drops to 19% per year (from 25% in the original study), with the oil pie being divided one-fifth for the companies, one-fifth for the federal government, and three-fifths for the State (almost exactly the same as in our original study). For the intermediate case, where the State gets a total take of 50% of the oil pie, the companies' DCF profit rate would be 23% per year, with one-half of the pie going to the State and about one-fourth each to the companies and the federal government. (See Table III-1.)

All these data indicate that even if we use the conservative assumptions of the DB Report, including very high estimates of company investment in Prudhoe Bay and relatively low field production rates, the companies will still achieve a high profit rate on Prudhoe Bay. Moreover, even under a 50% State income tax rate, the companies should still earn a more than adequate return to cover their investment and risks, and one which as we shall see later compares favorably with their other investment opportunities.

In terms of actual money, with the present State income tax rate, the total State take would be \$14 billion from 1977 through 1995, or about \$750 million per year. Increasing the State income tax rate to 50% would increase the State take to \$35 billion, or \$1,850 million per year. In the intermediate case, with a total State take of 50%, the State would get about \$28.5 billion, or \$1,500 million per year. For the present

TABLE III-1

COMPANY PROFITABILITY AND DIVISION OF "OIL PIE":

PRUDHOE BAY, 1977-95

	(1) Current Tax Structure*	(2) State Take Equals 50% of Oil Pie	(3) State Gets 50% Income Tax
A. Division of Oil Pie \$ Billion (%)			
1. State of Alaska	14.0 (25)	28.5 (50)	34.9 (62)
2. Companies	20.9 (37)	14.3 (25)	10.9 (19)
3. Federal Government	19.9 (35)	13.7 (24)	10.6 (19)
4. Other States*	1.5 (3)	-- (-)	-- (-)
5. Total**	56.3(100)	56.5 (99)	56.4(100)
B. Division of Oil Pie (\$ per Barrel)			
1. State of Alaska	1.80	3.66	4.48
2. Companies	2.68	1.84	1.40
3. Federal Government	2.55	1.76	1.36
4. Other States	.19	--	--
5. Total	7.22	7.25	7.24
C. Company DCF Profit Rate (Per Year)			
	29%	23%	19%

Bases: Combination of DB and "Tanzer Report" data and assumptions--see text.

* State of Alaska current take based on royalty and severance equal 20% of wellhead value, plus effective income tax equal 2.5%; other states assumed effective income tax rate equal 3.5% now and zero in two increased state tax cases.

** Totals are not equal because of rounding.

tax rate case the companies would get after-tax profits of \$21 billion, or \$1,100 million per year; for the 50% income tax case the companies would get \$11 billion or \$575 million per year; and for the intermediate 50% State take case the companies would get \$14 billion or \$750 million per year.

Finally, we may note the following per barrel figures for company profits in each of the three State income tax cases, as they will be useful for comparison with the companies' opportunities in other countries: present State tax rate, \$2.70; 50% income tax case, \$1.40; 50% State take case, \$1.85.

B. Oil Company Profitability Potential Outside Alaska

Turning now to the alternative possible sources of crude oil for the oil companies, in this section we will examine the profitability in the principal areas serving the U.S. market. Clearly the most important potential source of future crude oil for the U.S. is the Middle Eastern and North African countries. These OPEC members have about 60% of the world's oil reserves, and in recent years have been the fastest growing source of U.S. oil imports, increasing their share from 17% in 1970 to 39% in 1975 (during a period when U.S. crude imports increased from 1.3 million barrels per day to 4.1 million barrels per day, or threefold).¹ And just as clearly, the profitability potential for the oil companies from such oil countries is quite limited. (See Table III-2.)

Basically, all of the Middle Eastern and North African countries have either taken, or are in the process of taking, 100% ownership of their oil fields. (Where the companies still have an equity interest in production, the normal royalty is 20% and the income tax rate is 85%.) Hence, the principal profit possibilities for the companies now are as providers of technical skills and marketing outlets, for service fees. In most of these countries, the allowed fee is in the neighborhood of \$.15 to \$.25 per barrel. For example, in Qatar, the companies get about 15 cents per barrel, in Kuwait \$.19 per barrel, and in the most important country of all, Saudi Arabia, they

TABLE III-2

COMPANY COSTS, PROFITABILITY AND DIVISION OF OIL PIE
IN MAJOR PRODUCING AREAS (ESTIMATED)

	(1) Price of Crude Oil (Wellhead) \$ per Barrel	(2) Capital Plus Oper- ating Costs, \$ per Barrel	(3) =(1)-(2) Oil Pie (\$ per Barrel)	(4) Company Profits (or Fee) \$ per Barrel	(5) Company: Government Division of Oil Pie (% Shares)
Middle East and North Africa	12.50 to 13.00	.25 to .50	12.25 to 12.50	.15 to .25	2:98
Nigeria	14.00	1.00	13.00	.30	2:98
Venezuela	13.00	1.00**	12.00	.20	2:98
Indonesia	13.00	1.00**	12.00	1.00-1.50	12:88
North Sea	12.00	2.50	9.50	3.50	37:63
Canada	13.00***	2.00	11.00	1.25	11:89
Memo: Prudhoe Bay					
(a) Present Tax Structure	8.25	1.00	7.25	2.70	37:63
(b) 50% State Take	8.25	1.00	7.25	1.85	26:74
(c) 50% State Income Tax	8.25	1.00	7.25	1.40	19:81

Note: Data are approximate current estimates; for sources see text and footnotes.

* Capital costs normally predominate.

** Assumed for calculation purposes.

*** "Wellhead Value", based on controlled wellhead price plus export tax.

expect about \$.21 per barrel.² With crude oil selling at about \$12-\$13 per barrel, and investment costs in this area estimated at about \$.25-\$.50 per barrel, this means that the oil pie here is split about 2% for the companies and 98% for the governments.

The companies' profit potential in the other OPEC countries appears equally limited. In Nigeria, which accounts for 3% of the world reserves but 18% of U.S. crude oil imports, the companies' profit margins in 1976 were reduced to 30 cents per barrel (from 50 cents previously).³ With prices at about \$14 per barrel and production costs of \$1 per barrel this also implies a profit split of about 2% for the companies and 98% for the Nigerian government. Similarly, in Venezuela, which has 2% of the world's reserves but supplies 10% of U.S. crude imports, the wholly nationalized oil industry allows the oil companies a technical and marketing fee of about 20 cents per barrel.⁴

Finally, even in Indonesia, the other principal OPEC country supplying the U.S. market (9% of U.S. imports and 2% of world reserves), profit margins are now estimated at about \$1.00-\$1.50 per barrel.⁵ This is half of those in Prudhoe Bay, under the present Alaska tax structure, and in line with margins which would prevail under a 50% State income tax. Moreover, the companies' share of the oil pie in Indonesia, while the most favorable in all the OPEC countries, is still only about 12%, compared to 39% in Alaska under the present tax structure and 19% with a 50% State income tax.⁶

Coming closer to home, Canada is the other principal supplier of crude oil for the U.S. market, accounting for 15% of the total. However, Canada has only 1% of the world's reserves, and Eastern Canada is an importer of crude oil. Hence the Canadian Government has announced a policy of ending Western Canadian exports to the U.S. in the next few years.⁷ In addition, the profits for the oil companies in Canada, while higher than in most OPEC countries, are less than in Alaska, even under the highest tax case we have discussed. Specifically, in Canada, based on data provided by the oil companies, their profit margins appear now to be about \$1.25 per barrel.⁸ With the price of Canadian crude oil in the U.S. market about \$14 per barrel (consisting of a price controlled wellhead value of close to \$10 and an export tax of about \$4), and exploration and production costs about \$2 per barrel, the division of the oil pie is about 10%-12% for the companies and 88%-90% for the federal and provincial governments of Canada.⁹

Because Canada has a federal system analagous to that of the U.S., it is worth examining the Canadian profit picture in a little more detail. As of January 1, 1976, when the wellhead price for Alberta crude oil was price controlled at \$8 per barrel, there was a Canadian federal government export tax of \$4.60 per barrel added on, to roughly equalize the export price with the price of crude oil in the U.S. markets. Of this \$12.60 per barrel received by Canada, exploration costs were about \$1.35 per barrel and operating costs \$.50 per barrel,

which left an oil pie of \$10.75 per barrel. Of this the companies had net profits of \$.84, provincial taxes were \$3.74, and the federal income tax was \$1.57. Thus, on a percentage basis, the companies got 8% of the oil pie, the provincial governments 35%, and the federal government 57% (including the export tax, which was largely redistributed to Eastern Canada as an oil import subsidy).¹⁰

As of January 1, 1977, the wellhead price was raised to \$9.75, while the export tax was dropped to \$3.25 (which changes do not yet reflect the January 1 increases in OPEC prices). According to two Canadian oil companies (Imperial, an Exxon affiliate, and Ranger), of the wellhead price increase of \$1.75 per barrel, their profits increased by about \$.43 per barrel; adding this to the \$.84 per barrel reported previously, this would imply company profits of \$1.27 per barrel. Thus, it would appear that the companies' share of the oil pie now would be about 11%. The provinces on average received an additional \$.77 per barrel in this period, bringing their take to \$4.51, for about 41% of the oil pie. This leaves an estimated 48% for the federal government in Canada.¹¹

By way of footnote, while the Canadian federal and provincial governments take such a relatively large share of the oil pie, compared to the situation in Alaska, the pace of exploration drilling in Western Canada set new records last year.¹²

Finally, we might take further note of the other

principal foreign oil prospect, offshore Northwest Europe. Although most of the expected peak production of 5.5 million barrels per day by 1990 is likely to go to Europe, and will not be available for the U.S. market, still it is worth examining the companies' likely profitability here.¹³

Towards this goal, we have the benefit of a recent "composite" model of the area (called here the "North Sea")-- an average for 7 fields discovered by the end of 1975, and assumed similar sized discoveries beyond 1975.¹⁴ This model, which is worked out annually for the 1971-2012 period, shows an average profitability for the oil companies of about \$3.50 per barrel, with their share of the oil pie being about 37%. (The model uses the United Kingdom's tax rates since the differences between it and the Norwegian Government are relatively minor.) Based on the per barrel numbers, superficially it would appear that the North Sea is a better profit prospect for the companies than Prudhoe Bay, even under current State income tax rates, and much better if the State of Alaska increases its rates substantially.

The fallacy in this, however, is that investment costs in the North Sea are much higher than in Alaska. Thus, over the life of the model, the average investment cost in the North Sea is estimated at \$1.85 per barrel, compared to a maximum \$.75 per barrel for Prudhoe Bay (excluding, of course, the pipeline, which as DB notes: "represents a distinct, and very important, profit (as well as cost) center in the

integrated economics of North Slope oil."¹⁵ As a result, the all important DCF rate of return on North Sea investment is projected to be lower than in Alaska, rather than higher. Thus, for the composite North Sea model, the DCF profit rate for the North Sea is estimated to be about 19% per year. This compares unfavorably with the 29% per year DCF return we estimate the companies will make from Prudhoe Bay under the present State tax structure, and is the same rate as the companies would earn from Prudhoe Bay with a 50% State income tax rate in Alaska.

Finally, in analyzing the companies' alternatives to exploration and production in Alaska, one additional factor needs to be considered. Namely, for the oil companies, security of supply is becoming of increasing importance, and the U.S. clearly is the companies' most secure supply source. In the OPEC countries, the clear trend is for the governments to want the actual oil, rather than its market value in cash, and either use this oil internally or export it themselves. Even in the North Sea, as we have seen, the governments are taking participation in the new fields.

Since the oil companies need an assured supply of crude oil to reduce the risk on their investments in refining, marketing and transport facilities, it is clear that such a secure supply has more value to the companies than is measured simply by its market price. (Evidence for this is the bids for Alaskan royalty oil at a premium above market price.)

Moreover, in the past, when there was a glut of crude oil but the companies' per barrel crude oil profits were still quite high, there was a tendency to build refineries and marketing facilities which made little or no profit, but would serve as a sure outlet for the profitable crude. Today, with the world entering an era of crude oil scarcity, but low per barrel profits for the companies, investment in new refining and market facilities will have to earn much higher profits to be justified. The corollary of this is that for a company which has existing refining and marketing facilities, an assured supply of crude oil can greatly increase the value of these facilities. (Conversely, the inability to obtain crude oil can greatly reduce the value of such facilities.)

Furthermore, if OPEC's new conceptual approach to crude oil pricing is successful in the future, such oil will have a much higher price. The basic new idea is that oil exporting countries should value their crude oil not just at the price which makes it competitive with other energy sources, but they should also add on premiums. One premium would reflect the fact that, for the country, using up the crude oil as an energy source now will make it unavailable in the future for a more valuable use, as a petrochemical feedstock. On top of this, an additional premium should be added on to reflect the fact that petrochemicals are a basic element in modern industrialization, so a country's loss of the opportunity to make petrochemicals means a loss of industrialization opportunities.¹⁶ Thus, the

real value to a country of crude oil might not just be \$15-\$20 per barrel but, e.g., \$30-\$40 per barrel (leaving aside the effects of future inflation).

In the final analysis, the fact that crude oil in a world of long run scarcity may be far more valuable than is measured by its present market price is of considerable significance to the State of Alaska. Its most obvious significance has already been discussed--namely, that it makes Alaska as a secure supply source an especially desirable place to explore for crude oil. Its less obvious significance, however, is that it raises important questions as to what is the best approach for the State of Alaska in terms of the pace and type of development of its crude oil resources. These questions, however, are more appropriately discussed in the following chapter on the benefits and costs of increased oil taxation in Alaska. From the analysis of the present chapter, however, we can conclude that substantial increased State oil taxation is not likely to end the attractiveness of Alaska to the oil companies as a place for additional exploration, development and production.

IV. CONCLUSIONS: BENEFITS AND COSTS TO ALASKA FROM INCREASED OIL TAXATION

In the preceding chapters, we have seen that there has been a long history around the world of increases in government oil tax rates, which the oil companies have typically claimed would hurt exploration or production. We have further seen that these tax increases, which accelerated in the post-1973 period, have been large enough that even the maximum tax increase analyzed here for Alaska would be unlikely to deter the companies from future exploration and production in Alaska.

Since, however, there can be no absolute certainty about the question of the impact of increased taxation on the oil companies' behavior, in this final chapter we seek to answer the following question: "Assuming that the increased State taxation would reduce future exploration and development in Alaska, is it or is it not worthwhile to have the increased taxation?" To do this, we need to first estimate both the benefits to Alaska of the increased taxation, as well as the possible losses from reduced exploration and development, and compare the two. And second, we need to see if there are ways by which the State could use some of its benefits to help reduce any such losses.

The benefits to Alaska of increased taxation are fairly obvious. The initial benefit, of course, is the increased State revenues. In the two tax change cases we have considered, these amount to between \$15 billion and \$21 billion over the life of the main Prudhoe Bay formation alone, or about \$750 million to \$1,100 million per year. To put these huge numbers into some more recognizable perspective, the increased State tax revenues over the life of the main Prudhoe Bay formation would be between \$40 thousand and \$60 thousand for every man, woman, and child now living in Alaska. Moreover, there would be substantial increased tax revenues also from the two lesser formations in Prudhoe Bay, which have already been explored and would likely be developed even at the highest tax rate.

A secondary benefit of increased State oil tax revenues is that with proper planning these could be used to promote Alaska's economic development, both within and outside the petroleum sector, and thus have a "multiplier" effect. In contrast, if the increased State tax revenues are foregone, most of the money will flow out of the state as oil company profits and federal corporate income taxes. Particularly since the major oil companies in Prudhoe Bay already have more Alaskan crude oil than they can easily handle, they have even less incentive than other oil companies to reinvest in new exploration and development in Alaska. (Thus, for example, Arco has used part of its expected increased cash flow to buy a major copper producer, Anaconda, into which it expects to pour much additional investment.¹)

If we turn now to the costs of increased State oil taxation, the basic one claimed is that there will be reduced exploration and development investments in Alaska. In assessing this claim, it is necessary to distinguish between investment for exploration and investment for development. As we noted in our original report, exploration is a risky business which requires a high profit rate to cover the risk, but development is relatively safe and does not require the same high rate.² Moreover, the bulk of oil money for exploration and development is for the latter category.

Specifically, in the whole United States, in the 1973-75 period only about one-fourth of all wells drilled were exploratory, while the rest were development wells.³ The average annual amount spent on exploration and development (including lease payments) in this period was about \$10 billion; of this amount about \$1 billion was spent on geological and geophysical expenses and lease rentals.⁴ Thus, if as a rough assumption we assume that the division of exploration and development expenses is proportional to the number of wells drilled, and we add the geological and geophysical expenses to estimated exploration drilling costs, we find the total exploration effort to be about \$3.3 billion, or only one-third of the total exploration and development effort in the U.S.

For reasons to be discussed below, exploration is the most crucial part of the combined exploration and development effort, and the part which theoretically might be most hurt by

increased tax rates in Alaska. How much it might be hurt is impossible to say, although as discussed in the previous Chapter we do not think cutbacks by the companies would be very great. But, even if we are wrong, in this connection it is significant to note that the annual tax revenues on Prudhoe Bay foregone by the State by keeping its present tax structure, as compared to a structure with a 50% tax rate on the companies' profits, would amount to about \$1,100 billion per year, or about one-third of all of the exploration effort carried out by the companies in the whole United States. Put in this context, it would appear that any reasonably foreseeable amount of oil company exploration in Alaska which was "lost" because of the increased State tax rate could easily be "financed" by the State itself.

Thus, one possibility would be for the State to replace the "lost" exploration services by directly contracting with the numerous independent firms which specialize in this work and do much of the exploration effort for the major oil companies; this is an approach successfully followed by a number of Third World governments.⁵ Another possibility would be for the State to enter into a joint venture agreement with one or more companies to carry out the exploration effort. This approach has also been used successfully by other governments; the relationship may vary from one where the government pays its share of the exploration effort to one where the government gets its share on a "carried interest" basis, meaning that it pays only if the exploration effort is successful. (This latter approach

is used, for example, by the Norwegian government with its new North Sea licenses.⁶⁾

As for the much larger oil development effort, once successful exploration is carried out, funding for this in a world of oil scarcity should present no serious problems. If the oil is found by the State itself, through service contractors, it could either use its own money to develop the field, or borrow either from the capital markets or from independent refining companies which would be eager to obtain an assured supply of crude oil. If the oil were found by a joint venture, then normally the State's co-partners would use the oil themselves or could market it.

Ultimately, the question of how much development takes place will largely depend on the expected profit rates. Here we might note that a 15% DCF rate of return on development expenditures should be enough incentive for oil companies to develop any fields found. By way of indirect evidence, the firm of La Rue, Moore, and Schafer, Texas petroleum consultants, helped prepare testimony for the U.S. Congress which used a 15% DCF rate of return as the level necessary for exploration and development of new oil in the U.S.⁷ Again, in the previously discussed model estimating the likely new production from the North Sea, the British petroleum consulting firm of Gaffney, Cline & Associates uses a 15% DCF rate of return as its minimum for field development.⁸

In this connection, it might also be noted that if the

State has an equity participation in the exploration and development efforts, more development may take place than if the exploration and development efforts were left solely to the oil companies. This is because the State has a lower cost of capital and hence does not need as high a rate of return as the oil companies. Thus, for example, if the State seeks a 10% per year return on its investment, and a marginal field is found which would yield 12% on investments, the field would not be developed by oil companies seeking a 15% return.

Finally, our overall conclusion on this question of a comparison of the benefits and costs of substantially increased State oil tax rates can be summarized as follows. The benefits are clear and very large, while the costs are unclear and likely to be much less sizable. Given the history and current situation of the international oil industry, the cries that the State will ruin itself by increased oil taxation need to be discounted at a very high rate indeed. Thus, in our view the previously cited warning of the Vice President of Sohio that the State must beware of hurting the "little red hen" oil industry through increased taxation may cite the wrong literary reference. Indeed, it seems as if the little red hen may rather be a modern version of "Henny Penny", in the old fable "Chicken Little", who continues to cry, "The sky is falling" because an acorn has fallen!

Exploration and Development in Alaska: A Final Word

Having completed our assigned analysis, we would like to conclude with some observations about broader economic questions raised by the Study, which ought to be considered in developing an overall State oil policy. One key question is the following: "Even if increased State oil tax rates did slow the pace of oil exploration and development, is that necessarily bad?"

Thus, especially if the State keeps its oil tax rates low in order to maximize exploration and development, since most of the additional oil pie is also likely to leave the State, will not Alaska be recklessly wasting its precious non-renewable resources without adequate provision for future generations? After all, it must always be remembered that oil is not lumber, and a barrel extracted is a barrel gone forever. This is particularly significant if, as seems likely, over the long run the value of oil will be continually increasing.

Given these considerations, in our own view, the following would be a sensible overall strategy for the State of Alaska, in terms of the best interest of its people. First, the State should substantially raise oil taxes now, even if it cuts future exploration and development somewhat. Second, the State should temporarily cease leasing on its lands, until it effectively learns the oil business and how to operate in it. Third, and related, the State should invest some of its increased

tax money for a complete exploratory survey of its lands; only with comprehensive geophysical and geological data can the State have some idea of its potential resources (oil or otherwise). Fourth, given such a preliminary inventory of potential, the State should then directly contract for further exploration, or work with companies on a joint venture basis; even if the State decided to continue more traditional lease arrangements, however, at least it would then be in a better position to obtain a fairer share of the treasures which may lie on State lands.

The question of what position to take toward rapid exploitation of non-renewable resources is not an easy one. While there is a tendency to always equate rapid exploitation with progress, it should perhaps be a word of warning that some which have gone down that road in the past are less happy with it now. Thus, for example, the Premier of Alberta, Canada's leading oil producing province, last year urged a "go slow" policy on oil and gas development:

[Premier] Laugheed said squandering the province's resources now could leave "the dreadful legacy of turning Alberta into a have-not province."

Reviewing the rapid development since his government was elected in 1971, the Premier said, "if I had it to do over again, I would try to spread out the time frame of some of our decision-making in the first term."⁹

Again, the Norwegian government has taken the position that it does not want rapid exploration because if it is known that more oil reserves exist there, enormous pressure will be

exerted to rapidly develop these reserves, even if it is not good for the country.¹⁰

But, in the final analysis, these questions are part of the most basic question of the kind of life the people of a state or country seek. Yet, for the people to decide they must be informed--not only on the pros and cons of each individual question and policy, but also on the interrelationships between them. It is our hope that the present study will be a useful link in a chain of information and analysis that will help the State of Alaska, which is at a crucial crossroads in its history, to choose a fruitful path in the coming years.

FOOTNOTES

I.

1. The Anchorage Times, January 27, 1976, p. 6.
2. Ibid., October 26, 1976, p. 11.

II.A

1. Based on data from The Times (London, March 17, 1951, p. 4, and Keesing's Contemporary Archives, March 31-April 7, 1951 (p. 11367).
2. Ibid.
3. Keesing's Contemporary Archives, May 5-12, 1951, p. 11450.
4. Henry S. Grady, "Tensions in Iran", Vital Speeches of The Day, October 15, 1951-October 1, 1952, p. 373.
5. See David Wise and Thomas B. Ross, The Invisible Government (New York: Random House, 1964), p. 110.
6. See Michael Tanzer, The Political Economy of International Oil and The Undeveloped Countries (Boston: Beacon Press, 1969), p. 326.
7. Production data from United Nations, World Energy Supplies: 1950-1974 (New York: United Nations, 1975), p. 70; hereafter cited as WLS.
8. Petroleum Intelligence Weekly (PIW), June 13, 1966, p. 2.
9. PIW, September 19, 1966, p. 6.
10. Calculated from data in PIW, October 17, 1966, p. 1.

11. Ibid., p. 2.
12. WES, op. cit., p. 70.
13. PIW, December 12, 1966, p. 6.
14. WES, op. cit., p. 70.
15. PIW, June 13, 1966, p. 5.
16. Calculated from data in PIW, September 19, 1966, p. 6, and October 17, 1966, p. 1, which imply average prices of about \$1.92 per barrel, F.O.B. Venezuela.

II.B

1. The Petroleum Economist (PE), March 1975, p. 99.
2. PIW, March 1, 1976, p. 1.
3. Ibid., p. 2.
4. PIW, June 28, 1976, pp. 3-4.
5. Platt's Oilgram News Service (Platt's), September 22, 1976, p. 3.
6. Based on data for January through November, as reported in PIW, December 20, 1976, p. 10.
7. Ibid.
8. Far Eastern Economic Review (FEER), January 28, 1977, pp. 38-9.
9. One unsettling factor was the U.S. Treasury ruling in early 1976 that oil tax payments paid to countries like Indonesia might in the future be treated as royalties and not as income tax payments, and hence the U.S. income tax liability of the companies would rise.
10. World Oil, August 15, 1976, p. 190.

11. Based on data in Ibid., pp. 190-4, and American Petroleum Institute, Basic Petroleum Data Book, Section III, Tables 11a and 12a (April 1976); hereafter cited as API Data Book.
12. The mid-1973 profit split is from data in the Economist (London), July 7, 1973, Survey, pp. 16, 19.
13. PE, January 1975, p. 4.
14. PE, May 1976, p. 177.
15. PE, December 1976, pp. 458-60.
16. PIW, February 2, 1976, p. 2.
17. Ibid.
18. PIW, February 9, 1976, p. 3.
19. PIW, February 2, 1976, p. 2.
20. PIW, December 20, 1976, p. 11.
21. Platt's, November 24, 1976, p. 2.
22. Ibid., p. 3, and PIW, January 10, 1977, p. 11.

23. Platt's, October 13, 1976, p. 1.
24. Platt's, November 1, 1976, p. 2.
25. PIW, November 15, 1976, p. 8.
26. Platt's, November 9, 1976, p. 4.

III

1. Tanzer Economic Associates, Inc. "Alaska's Prudhoe Bay Oil: Profitability and Taxation Potential (A Report to the Alaska State Legislature, January 9, 1976), pp. 75-6; hereafter cited as Tanzer Report.

III.A

1. Drexel Burnham & Co., Inc., "The North Slope: Paradise Lost?" (April 27, 1976; hereafter cited as DB.
2. DB, pp. I-11 to I-14.
3. Ibid., Appendix Table II-E.
4. Ibid., p. IV-3. The DB "Reserves Constraint" case was adapted, with interpolated and extrapolated production figures as follows (millions barrels per day): July-December, 1977, 6; 1978-85, 1.5; 1986-90, linear interpolation to 1990=1.045; 1991-95, 15% per year decline.
5. Ibid., Appendix Tables II-E, II-G.
6. See DB, p. IV-21 for discussion of federal tax treatment.
7. For a discussion of the reasons see the Tanzer Report, pp. 38-40.
8. At the same time, we assume the companies will pay an additional 3.5% effective income tax rate to other state governments in the U.S.: these implicit effective income tax rates for State of Alaska and others are derived from data in "Sohio Submission One", dated October 28, 1976.
9. DB, IV-21.
10. Assuming operating and depreciations cost of about \$1.00 per barrel.
11. DB states "If prices of domestic crude are constrained below import parity, as we deem likely, then the movement of Prudhoe Bay into the more distant markets would not

likely result in a lower netback than if Alaskan oil were marketed solely on the West Coast." (p. IV-27).

III.B

1. Calculated from API Data Book, Section II, Table 3, and Section IX, Tables 4a and 4b.
2. Data from PIW: October 18, 1976, pp. 3-4; March 29, 1976, p. 2; November 1, 1976, p. 3.
3. PIW, October 18, 1976, p. 6.
4. Ibid., p. 3.
5. PIW, January 1, 1977, p. 7; FEER, January 28, 1977, pp. 38-9.
6. Indonesian data from PIW, January 10, 1977, p. 7.
7. Canada plans to end all crude exports to the U.S. by 1981 (PE, August, 1976, p. 297).
8. Based on data from Oil and Gas Journal (OGJ), April 26, 1976, p. 66 and PE, August 1976, p. 297.
9. Ibid.
10. OGJ, April 26, 1976, p. 66.
11. PE, August 1976, p. 297.
12. Platt's, August 13, 1976, p. 3; data for first seven months of 1976.
13. Peak production estimated by model of Gaffney, Cline & Associates, U.K. petroleum consultants, as reported in PE, December 1976, p. 458.
14. Ibid., pp. 458-60; the model covers about 40 billion barrels in reserves, of which 20 billion have been already

proven in the North Sea itself and a "significant proportion" of the additional reserves are also expected to come from extension to these existing fields.

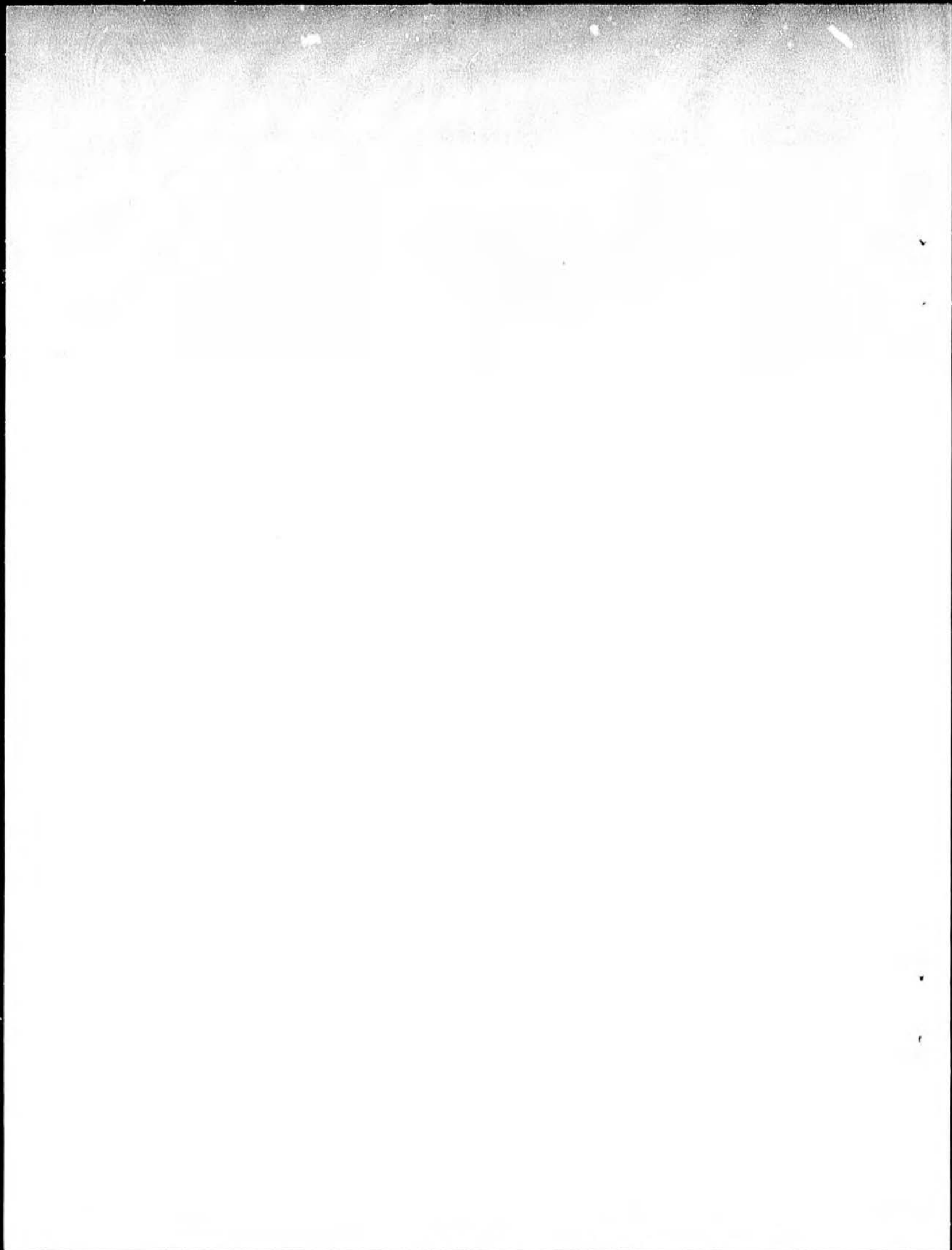
15. DB., p. IV-6.
16. The basic approach is that of the Organization of Arab Petroleum Exporting Countries (Platt's, Nov. 8, 1976, p. 3).

IV

1. See Forbes, July 15, 1976, pp. 67, 69.
2. Tanzer Report, pp. 78-9.
3. API, Section III, Table 2.
4. Based on data in API, Section V, Table 9 and Chase Manhattan Bank, Financial Analysis of a Group of Petroleum Companies: 1975.
5. For example, see the Tanzer Report, p. 88.
6. On Norway, see PE, March 1976, p. 105.
7. Testimony of Robert R. Nathan, April 28, 1975, reprinted in "Gas Production and Supplies" (Joint Hearings before the U.S. Senate Committees on Commerce and Government Operations), Serial No. 94-44 (Washington: U.S. Government Printing Office, 1975), p. 235, and criticised on pp. 241-51.
8. PE, December 1976, p. 459.
9. Platt's, April 7, 1976, p. 2.
10. "Once discoveries are made, technical, economic and political reasons make it difficult to limit their

exploitation. Exploration activities should therefore be regulated by the size of finds already made.

"Desiring a long-term exploitation of resources and on the basis of its overall assessment of the social implications, the Government has come to the conclusion that Norway should maintain a moderate rate of extraction of the petroleum resources." (Royal Norwegian Ministry of Finance, Parliamentary Report No. 25 (1973-74): Petroleum Industry in Norwegian Society, p. 6).



W&M: Tanzer⁷⁵

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February 13, 1976

Senator John Huber
Chairman,
Special Committee on Taxation and Revenue
Alaska State Legislature
Pouch V
Juneau, Alaska 99811

Dear John:

Thank you for sending me a copy of the Rush Moody report on "Legal Analysis of Issues Relating to Natural Gas Transportation." I did indeed find it quite interesting and informative. While I am not competent to comment on the legal issues analyzed, I am happy to respond to your request for comments or recommendations on the report, as it may touch on economic questions. This letter represents my initial reaction to some of these matters:

1. As I understand the Moody report, a key legal conclusion is that the State should take royalty gas in kind rather than in value; otherwise, it may lose control in the future of this royalty gas because it will come under FPC regulation, and thus it would be possible that none of Alaska's natural gas would be available for consumption within the State.

2. From an economic point of view, I think the State would also be wise to take royalty gas (and maybe royalty oil also) in kind, so as not to lose the future option on having the royalty gas. This is particularly true because the real value of the royalty gas to the State may be much higher than its market value, for the following reasons.

3. First, at present the price of FPC regulated natural gas moving in interstate commerce is about one-fourth its real market value, as measured by prices on intra-state sales (50¢ versus \$2.00 per MCF). While natural gas prices may be deregulated in a few years, there is no present certainty on this.

4. More important, in the long run I think it is generally agreed that the use of natural gas for its heat content as a fuel is a waste of a valuable resource, since its greatest value would be as a petrochemical feedstock. This suggests among other

things that over the long run natural gas prices will rise as it increasingly is reserved for its more valuable use.

5. But, because of the high profit rates the oil companies use in their DCF calculations (as discussed at length in my report), their decisions will tend to be made on short run profit considerations, which may not be best for the State. By way of hypothetical illustration, I constructed a case to show where it might be better for the State to have the gas stay in the ground until it became more valuable, while for the companies it would be more profitable to produce quickly. The hypothetical assumptions were that natural gas would sell at \$2 per MCF in the 1980s, \$6 per MCF in the 1990s, and \$18 per MCF thereafter. Assuming a time value of money, or discount rate, for the companies of 20% per year and for the State of 10% per year, it turns out that if a gas field has a 20 year life, the companies would be best off producing all the gas in the 1981-2000 period, while the State would be better off with the gas produced in the 1991-2010 period. (See attached table.)

6. The problem of the State having a lower discount factor, and hence a longer time horizon, than the companies is of course a general one which may lead to conflicts of interest in many oil and gas areas. Thus, for example, it may be better for the State if all oil and gas were produced at a slower rate than the companies would like, and it is possible that this could be handled under conservation regulations. Specifically, however, with regard to its royalty gas, if the State decides it would be better off with gas production at a slower rate than the companies want, perhaps a way could be worked out to require the companies to leave the royalty gas in the ground until the State requests it, either for its own use or for resale. Alternatively, the State could perhaps exchange the royalty gas with companies for "future gas" to be delivered by them when desired by the State.

7. Another factor favoring taking of royalty gas in kind is that market prices of gas may not reflect the full economic cost to the State of not having the gas. In the short run, a lack of gas could mean costly shutdowns of industry and great consumer inconvenience. In the long run, the absence of an assured supply of gas might hinder the whole economic development of the State. Thus, the question of royalty gas cannot be divorced from questions of planning long-run economic development. But, at least keeping the option to take gas in kind does not foreclose future industrial development opportunities.

8. Also, I think taking royalty gas in kind would have the advantage that it will help the State learn more about the oil and gas business, from practical experience. With oil companies fully integrated from the raw material through petrochemicals, and with the allocation of costs between oil and gas production,

and between raw material production and other functions, often being arbitrary, it is important for the State to have a good grasp of the practical economics of the gas business as well as the oil business. This is vital for the State even if it is to simply maximize its benefits as a tax collector.

9. Finally, I certainly agree with the Moody Report's general recommendations that State leasing policies and taxation on natural gas should be reconsidered. In my opinion both of these questions call for detailed study of possible alternatives. Here I would only observe that tax rates in Texas and Louisiana, where the oil companies have widespread political support from small producers, would not normally be an adequate yardstick as to what rates of taxation could be imposed.

I hope these general comments will be of use to you. My thanks also for your kind words about my report.

Yours sincerely,

Michael Tanzer

Dr. Michael Tanzer,
President