SCOMM

#12:13

Drexel Burnham & Co.
INCORPORATED

RADEK

TABLE OF CONTENTS

AGO 531505

Page

TELEPHONE 344-1400
CABLE ADDRESS
COBURNHAM

...LOS ANGELES
MIAMI/OAKLAND/SAN FRANCISCO
ST. LOUIS/WHITE PLAINS
TORONTO/AMSTERDAM/BRUSSELS
GENEVA/LONDON/PARIS/TOKYO

THE NORTH SLOPE: PARADISE LOST?

SUMMARY AND CONCLUSIONS

Perspective

Despite the frustrations and delay in moving North Slope crude to market, and escalating costs, North Slope earnings prospects--while still under attack--have never looked better, thanks to the surge in crude prices worldwide and in the United States. Since mid 1972, the surge in exempt crude prices has importantly overshadowed hefty escalations in the estimated cost of TAPS and field development, resulting in a handsome widening of prospective profit margins. Per barrel profits, calculated on recent parameters (crude price, cost estimates, tax policies, production prospects, and market outlook) could approximate \$3.18 a barrel, divided \$1.03 a barrel on TAPS and \$2.15 at the wellhead, at a 1980 crude production rate from the main Prudhoe Bay reservoir of 1,500 thousand barrels daily. This \$3.18 barrel compares with only \$0.95 a barrel estimated two years ago.

Investors had been deeply disturbed by the unrelenting increases in TAPS cost estimates prior to the OPEC-induced explosion in global crude prices at the turn of 1973/1974. In December 1972, Standard of Ohio had reported an estimate of TAPS cost, inciding construction interest, of \$2.9 billion for capacity of 1.2 million B/D (over \$3.1 billion for capacity of 2 million B/D). By late January 1976, Alyeska had raised its official estimate of TAPS capital requirements to \$7 billion. Construction interest will raise initial costs to \$8.3 billion (a staggering sum for an outsized gathering line). Expansion of TAPS to 2 million B/D, to cost an additional \$855 million, will bring ultimate cost of the pipeline to \$9.16 billion. As a result, the prospective TAPS tariff has risen to \$4.60 a barrel compared with \$1.50 (calculated on an I.C.C. basis) two years ago. Moreover, marine costs between Valdez in southern Alaska and Los Angeles have increased from \$0.35 to \$0.50 a barrel, reflecting inflation in tanker construction costs, higher bunker costs, and soaring hull insurance premiums.

Investors have also begun to witness enormous upward revisions in development costs. We surmise that the capital cost of developing the 9.5 billion barrels of proved reserves in the main Prudhoe Bay field could cumulate to \$7 billion, or 75¢ per barrel. The conventional wisdom had long placed such expenditures at \$2 billion, or 21¢ per barrel.

Fortunately for North Slope prospects, crude prices began to rise in 1973, and then surged, thanks to OPEC. The posting of Signal Hill (27° API gravity)

NORTH SLOPE OF ALASKA
CALCULATION OF PER BARREL EARNINGS IN 1980:
CURRENT PARAMETERS VERSUS 1972 PARAMETERS

(Dollars Per Barrel)

		Spring 1976 Proposed Tax Laws	Spring 1976 Current Tax Laws	Summer 1972
(1)	California Price	$11.00[a]	$11.00[a]	$3.19[b]
(2)	Tanker Cost (Valdez-L.A.)	0.50	0.50	0.35
(3)	(1-2) Price at Valdez	10.50	10.50	2.84
(4)	TAPS Tariff	$ 4.60	$ 4.60	$0.88[c]
(5)	Costs (incl. Taxes)	3.57	3.57	0.80
(6)	Pipeline Earnings	1.03	1.03	0.08
(7)	(3-4) Wellhead Price	$ 5.90	$ 5.90	$1.96
(8)	Costs (incl. Taxes)	4.40	3.75	1.09
(9)	Production Earnings	1.50	2.15	0.87
(10)	(6+9) Integrated Earnings	$ 2.53	$ 3.18	$0.95

a. Possible "upper-tier" price for Signal Hill (27° API) crude at year-end 1976.
b. Posted price for Signal Hill (27° API) crude.
c. Compared with I.C.C. tariff of $1.54; we then assumed the companies would elect to live with a 2% return on TAPS to minimize Alaskan taxation on integrated operations (discussed later).

crude in California, $3.19 a barrel in the spring of 1973, had climbed to $4.79 a barrel by year-end 1973. The two-tier system for pricing domestic crude, introduced in August 1974, then permitted "new" (uncontrolled) crude prices to depart from "old" (controlled) crude prices. Exempt Signal Hill crude was subsequently drawn up by OPEC's cartel-imposed prices for imports to more than $11 a barrel. This price was recently rolled back to $10.27 a barrel by the Energy Act of 1975. Under that same act, the "upper-tier" (new) price with move back toward $11.00 a barrel by the close of 1976.

Accordingly, the debt owed to OPEC for the still favorable outlook for North Slope crude may be illustrated: as noted, "yesterday's" posting for Signal Hill (27° API gravity) crude was $3.19 a barrel; today's integrated cost (i.e., average total cost) of the project, assuming a profitless TAPS, is almost $3.60 a barrel. Integrated "cost" of moving a barrel of North Slope crude to the West Coast, assuming a profitable TAPS but no profit at the wellhead, would

AGO 531508

approach $6.50. Domestic crude prices were already beginning to move higher in 1973, absent OPEC's cartel pricing--how much higher is now moot, but certainly not to $11.00 a barrel.

Outlook

Concern over escalation in costs and the risk of protracted delay is completing either TAPS or field development is fading fast. The costs of bringing North Slope crude on stream by mid-1977--to exceed $12 billion--are now essentially in place. Further increases in project costs, while quite likely, will probably be of tolerable proportions. Major increases in costs are most likely to relate to significant increases in proven reserves. Longer term, development of the Kuparuk and Lisburne reservoirs, possible investment in tertiary recovery in the main (Sadlerochit) reservoir, and development of gas production could add billions more to capital outlays over the life of the project. The economics of investing in all of these areas would be impaired, perhaps irreparably, if Alaska adopts the stiff increases in taxation recently proposed for oil and gas production. The risk of protracted delay in completing TAPS is minor. In fact, the project will probably be completed on, or even ahead, of schedule.

Major areas of investor concern regarding the North Slope oils include (1) a precipitous drop in OPEC prices, (2) the future of controls on U.S. crude prices, (3) untoward trends in Alaskan tax laws, and (4) possible delay in constructing a transportation system to move Prudhoe Bay crude to the Midwest.

The paramount issues of North Slope economics are, in our view, the two interdependent issues of crude prices and U.S. and Alaskan taxation. OPEC has decisively withstood the test of adversity and, in our judgment, will remain essentially intact at least well into the 1980's. We therefore expect prices for OPEC crude to rise steadily, although perhaps moderately, over the medium term. While we expect domestic crude prices to remain on relatively high ground, we also expect Congress to permit scheduled expiration of price controls only if the OPEC ceiling moves up very gradually indeed (or, better yet, declines). Alaska appears to be ensuring that in the United States, as abroad, "progressive" tax policies can threaten to severely constrain the upside earnings potential implicit in high, or rising, crude prices. We, nonetheless, profess to optimism about the ultimate outcome of the Alaskan tax debate. The tax changes proposed so far in Alaska would still leave the companies with "acceptable" unit margins, in an environment of slowly rising crude prices. The issue of increased taxation on Alaskan oil and gas will not be settled once and for all time, whatever the fate of the initially proposed tax package.

This report is primarily an appraisal of the economics of North Slope oil and gas. We examine a variety of plausible models of volumetric prospects and a range of pricing possibilities from major setback to moderate appreciation. We work towards a matrix of earnings possibilities for North Slope oil and gas. We examine separately the admittedly interrelated variables of crude price and taxation on production earnings. As noted, our own conclusions are biased in favor of crude prices, at least in money terms, remaining on high ground, but with governments assessing the "adequacy" of profit margins. In so doing, Alaska would continue to emphasize the indicated discounted rate of return on production only (now around 23% based on near-term prices and taxes), while the companies will point to an approximate 14% return on the integrated project. Those who disagree with our conclusions, nevertheless, can find the report useful to test the earnings possibilities on the North Slope under less attractive assumptions. A constructive posture on Atlantic Richfield ($90 1/4) and Standard of Ohio ($69 1/4)--overwhelmingly so in the case of Sohio--must rest upon a leaning towards an optimistic scenario being the most probable one. Our own BUY recommendations for ARCO and Sohio rest upon such assumptions.

Chapter I of the report reviews the cost components of the project and assesses the risk of delay in completing the project. We then examine the economics and political parameters that will govern the companies' profit margins on crude. Clearly, the major factors are crude prices (analyzed in Chapter II) and taxation (examined in Chapter III). Chapter IV presents the analytical models that bound the earnings possibilities in the transportation and production functions. Our earnings models are differentiated as to pipeline throughput and production volumes, and crude price and tax assumptions. Chapter V translates the models into matrices of earnings possibilities for Atlantic Richfield and Standard Oil of Ohio. Chapter VI examines the regulatory, political and economic factors that will govern the start-up date for production, the destination, and prospective earning power for North Slope gas. Our final chapter translates the industry cost analysis into the specific capital requirements (past, present, and future) of ARCO and Sohio. It also examines patterns of financing to date, shortfalls, and the forms that future financing might take. Obviously, the way the companies finance will affect their future earnings per share.

Our formal projections of pipeline tariffs and earnings are based on capital costs which are a shade lower than the latest estimate. We have not changed our earnings models on this account. The gain in analytic purity from reworking the entire exercise is minor. *Ceteris paribus*, the higher the pipeline cost, the higher the TAPS tariff would tend to be pressed. It does not follow that the tariff would necessarily be raised, nor, if it were, that integrated profitability would be much affected. However, we do take into account the full January 1976 increase in TAPS estimated cost in our discussion of financing.

The appendix tables present detailed exercises for all our earnings models.

THE TRANS ALASKAN PIPELINE SYSTEM AT A GLANCE

TAPS AGREEMENT

Duration: initial term, 30 years

Form of Ownership:
undivided joint interest

Transfer of Ownership:
- permissible, for cash
- partners have first purchase rights

Expansion from 1,200 TB/D to 2,000 TB/D:
- any participant may propose
- other partners may acquire proportionate shares or decline
- each partner has option to acquire share for 2 years after expansion

TAPS OWNERSHIP

	Revised as of July 1974[a]	Original[b]
Std. of Ohio	33.34%	27.50%
BP	15.84	0.58
Atlantic Richfield	21.00	28.08
Exxon	20.00	25.52
Mobil	5.00	8.68
Union	1.66	3.32
Phillips	1.66	3.32
Amerada Hess	1.50	3.00
	100.00%	100.00%

a. Capacity of 1,200 TB/D
b. Capacity of 600 TB/D

PIPELINE DATA

Completion: mid-1977
Diameter: 48 inches
Length: 798 miles
Initial design capacity: 1,200 TB/D
Ultimate design capacity: 2,000 TB/D

Pump stations:
5 for startup at 600 TB/D by July 1977
3 additional to raise capacity to 1,200 TB/D by November 1977
4 additional to raise capacity to 2,000 TB/D

Environment:
Temperature range - −80°F to 90°F
Continuous permafrost - 250 miles
Terrain - 3 mountain ranges, 70 rivers and strea
Major earthquake fault in Alaska Range

MODES OF PIPELINE CONSTRUCTION

Conventional burial (insulated pipe resting on bedding), 380 miles

Elevated (insulated in fiberglass jacket on cross beams between flexible vertical supports), 410 miles

Special burial (double insulation; circulating brine in pipe running along bedding), 8 miles

VALDEZ TERMINAL

Port: deep-water, ice-free fjord
12 miles long, 2½ miles wide

Tank farm:
initial storage, 9 million barrels, (18 tanks)

Marine terminal:
5 berths
4 handling 150,000 DWT tankers
1 handling 120,000 DWT tankers

TAPS COST ESTIMATES

At initial design capacity of 1,200 TB/D:

Capital	$7.0 billion
Construction interest	1.3
	$8.3
Expansion to 2,000 TB/D	0.9
Total	$9.2

Company costs:	at Capacity of 1,200 TB/D	at Capacity of 2,000 TB/D
Std. of Ohio	$2.8 bill.	$3.1 bill.
BP	1.3	1.4
Atlantic Richfield	1.7	1.9
Exxon	1.7	[illegible]
Other	0.8	[illegible]

THE PRUDHOE BAY FIELD AT A GLANCE

GENERAL DESCRIPTION

Location: North Slope of Alaska

Area: 45 miles, east-west
20 miles, north-south

Reservoirs: Sadlerochit -- main
Jurassic - Triassic

Lisburne -- deeper reservoir extending east of main reservoir

Kuparuk -- shallower Cretacious, extending over broad area to west of main reservoir.

MAIN RESERVOIR DATA

Proved reserves:
oil, 9.5 billion barrels
gas, 24 trillion cubic feet

Pay thickness:
630 feet (porous, permeable sandstone)

Depth:
up to 9,000 feet

Large gap cap; enormous water face

Crude:
27° API Gravity, 0.82% sulphur

Gas/oil ratio:
tested at 740 cu. ft. per barrel

COMPANY NET PROVED RESERVES

Main Reservoir:

Crude and Condensate (billion barrels):

Std. of Ohio	3.9E	47%
BP	0.5E	6
Atlantic Richfield	1.7	21
Exxon	1.7	21
Other Companies	0.5	5

Natural Gas (trillion cubic feet):

Std. of Ohio	6.2	30%
Atlantic Richfield	7.0	33
Exxon	7.0	33
Other Companies	0.8	4

Reserves shown exclude Alaskan royalty crude.

PRODUCTION

Main reservoir capacity:
approximately 1,500 TB/D based on currently proved reserves

Kuparuk/Lisburne reservoir capacity:
400 TB/D + (speculative)

Water injection in main reservoir likely - to sustain production

Miscible drive a good possibility - to increase recoverable reserves in main reservoir

Alaska must approve MER
Natural gas initially reinjected

PRODUCTION FACILITIES

Producing wells:
initially 130
drilled from 22 pads

Flow Stations:
4 in 1977
2 in mid-1978
total capacity-1,800 TB/D +

Gas Compression plant:
8 low-pressure trains
4 high-pressure units
capacity-1.66 bill. cfd

Power Plant

Handling capacity of combined facilities: 1,600 TB/D

DEVELOPMENT COSTS (MILLION $)

Development of Proved Reserves (9.5 bil. bbls.)

1969-1978:	Field Capacity 1,200 TB/D	$3.3 bil
	Increment to 1,500 TB/D	0.6
	Subtotal	$3.9 bil
	ARCO Share	1.1
	Exxon Share	1.1
	Sohio Share	1.6
Post 1978 Field Maintenance		$3.0 bil
Kuparuk/Lisburne Oil Development		3.0

while others are required by the terrain.

Geotechnical (geologic-soil) conditions have been quite problematic. One type of geotechnical problem--but not the worst--has found drilling equipment often mismatched to soil conditions (for example, encountering rock where gravel is expected), causing expensive delays. Another more serious type of geological surprise has been the encountering of massive ice and permafrost where ice-free gravel or rock had been expected, requiring elevation of an additional 50 miles of pipeline. The longest stretch affected is a 25-mile stretch in Section 2 (south of Fairbanks) between the Salcha River and Sourdough. The redesign and construction will be expensive and will require an additional 300-man construction camp and expansion of an existing camp. As noted previously, the number of VSM's will approach 78,000, up from the 72,000 estimated six months ago. The cost of drilling and inserting each pile averages $5,000. Alyeska has VSM's on open order, so no shortage of piles is expected.

Several potentially serious, and certainly costly, problems were also encountered at the Valdez terminal site because of unexpected soil and rock conditions. In one case, more overburden than anticipated was encountered because of misleading test borings at the tank farm site. Also, foundation rock was found to be not as competent as earlier borings had indicated. This necessitated the removal of huge amounts of overburden (14 million cubic years versus the 9 expected), the quarrying of rock, and construction of adequate tank foundations requiring enormous quantities of concrete fill and steel piles driven as deep as 50 feet. In the second half of 1975, a large rock slide behind the vapor recovery unit at the terminal slowed work there and made it necessary to cut away large quantities of potentially unstable rock or bolt it into place. This process involved drilling holes horizontally into the rock, inserting bolts about 30 feet in length, and grouting them into place. The degree of effort reflects the realization that Valdez is a prime earthquake zone. Remarkably, construction of the tank farm and other terminal facilities remains on (or ahead of) schedule.

Outlook for TAPS Costs and Completion

The cost of threatened, but averted, delay takes the form of greater commitments of manpower and other resources--in short, higher capital costs. The cost of actual delay takes the form of delayed revenue (heavier discounting of future revenues) and aggravation of financing problems. As noted, Alyeska has managed to avert actual delay, even if sparing no cost in doing so.

Repeated or prolonged labor stoppages are more than possibilities. Alyeska has encountered considerable disruptions of work dispite the absence of the usual gripes over wages or living conditions. Renegotiation of the wage contract in June 1976 could involve work stoppages. The settlement will probably be exorbitant. Low productivity of labor may continue to pose obstacles to timely completion of the project, or else to necessitate higher-than-expected employment.

Adverse weather conditions are fully as likely to threaten or cause construction delay. Heavy rains and severe winter weather have already occurred and been overcome--at a price--and barring truly extraordinary adversity, Alyeska will probably cope again. The containment of a recent North Slope oil spill--caused by a sudden temperature change--points up the protective measures anticipated by Alyeska and supervisory government watchdogs. One should not be too surprised if the weather causes occasional bugs in the smooth functioning of TAPS in its early winters of operation.

The prospect of major new geologic surprises is unlikely now that recoring has been done and all major foundation sites throughly explored, if not constructed, both at the Valdez terminal and on the North Slope.

TAPS represents the first above-ground placement of large diameter pipe in the United States; the effort has proved highly successful so far. The VSM's have held up well. Adaptation of familiar equipment has been achieved in numerous instances; new technology has been tested and either accepted or rejected. In contrast, design changes will continue, but will be handled expeditiously as at present. As noted, continuing smooth operation of the strategic Yukon bridge will facilitate movement of men, materials, and equipment.

The one major risk not yet encountered is an earthquake. Alyeska has invested heavily in specially-designed materials, engineering, line blocks, and detecting equipment to deal with the threats of earthquake-related pipeline breaks and oil spillage. Storage tanks, the power plant, and ballast water treatment and vapor recovery facilities at the Valdez terminal are all located on high elevations to escape possible tidal waves unleased by earthquakes.

Continued............

NORTH SLOPE PROJECT: EVOLUTION OF COSTS AND STATUS OF CONSTRUCTION

Introduction and Summary

This chapter examines the evolution of investment costs for the principal components of transportation and production of the North Slope project as required for startup of production by mid-1977 and for maintenance and possible expansion of production over the longer term. It also reviews the status of various phases of construction and the factors that have to date temporarily caused setbacks in scheduling and that conceivably could result in future delay.

The costs of bringing North Slope crude on stream by mid-1977 are now essentially in place. In late January 1976, Alyeska raised its official estimate of TAPS capital costs for capacity of 1.2 million barrels daily to $7 billion. Interest during construction will raise that figure to about $8.3 billion. The estimated cost of developing the main field to an initial capacity of 1.2 MM B/D will approximate $3.3 billion; expansion of capacity to 1.5 million B/D would raise the total to $3.9 billion. The total cost (including tankers) of bringing Prudhoe Bay crude production on stream will exceed $12 billion.

Although the companies are approaching the final phase of construction preceding startup, further escalation in project costs cannot be ruled out. However, such increases are likely to be of tolerable dimension.

While the past focus of investor concern has been the quantum jumps in estimated pipeline costs, investors have begun to witness enormous upward revisions in development costs. Fortunately, a large portion of these increases in development costs will occur only after the North Slope project has begun to yield large cash flows. Meanwhile, considerable disagreement exists over the eventual total cost of developing proved reserves in the Prudhoe Bay field. We surmise that the total investment cost over the life of the main field could amount to $7 billion, or 75¢ per barrel. The conventional wisdom had long placed expenditures for developing proved reserves at $2 billion or 21¢ per barrel. Clearly, the costs of North Slope oil are not nearly so attractive as once anticipated. Owing to the enormity of North Slope reserves, however, sizeable inflation in development (as also pipeline) costs will still average out to relatively low levels per barrel (or per MCF) when compared to unit costs for new discoveries in the lower 48 states and, more importantly, in relation to projected quantum jumps in realizations for "new" crude.

Longer term, development of the Kuparuk and Lisburne reservoirs, possible investment in tertiary recovery in the main (Sadlerochit) reservoir, and development of gas production could add billions more to capital outlays over the life of the project. The economics of investing in all of these areas would be impaired, perhaps irreparably, if Alaska adopts the stiff increases in taxation recently proposed for oil and gas production.

We note the growing divergence among various unit costs for individual companies although these differences, so far, tend to cancel one another out on aggregation. Models of project earnings thus retain their utility for analytical purposes.

We also note the persisting, but rapidly shrinking, uncertainty regarding dates of completion for critical components of the project. At year-end 1975, construction on the overall project was slightly ahead of schedule. The most probable threat to timely completion of the initial phase of construction is the risk of prolonged work stoppages on TAPS--a danger averted so far. Other impediments to completion by mid-1977 can be overcome through the application of ever more men and equipment to the job. The weather, no matter how capricious, is not likely to retard progress on the pump stations and on the terminal at Valdez, since most of the work remaining for next winter will be carried out indoors. The last phase of pipelaying will be conducted during the summer and fall of 1976. The prospect of major new geological surprises is unlikely now that recoring has been completed and all major foundation sites thoroughly explored. In addition, required new technology has now been tested. Another major threat to the construction schedule, one not yet encountered, would be an earthquake. Barring this eventuality, the project will probably be completed on, or even ahead, of schedule--at cumulative costs not outrageously different from current estimates.

Trans Alaskan Pipeline
Costs

In late January 1976, Alyeska raised its official estimate of TAPS capital cost (excluding capitalized interest during construction) for 1.2 million B/D capacity to $7 billion, up $625 million or 9.8% from the August 1975 estimate of $6.38 billion.* The latest hike in capital cost automatically raises interest during construction on the 85% debt portion of capital, by our reckoning, from $1.17 billion to perhaps $1.3 billion, bringing total startup cost to $8.3 billion. Subsequent expansion of capacity from 1.2 to 2.0 million B/D, to cost at least $855 million, will raise the ultimate cost to almost $9.16 billion.

Construction interest on the TAPS debt constitutes a major component of TAPS' eventual cost, growing inexorably with each escalation in TAPS capital cost. Our own $1.3 billion plus estimate of interest during construction assumes an average interest cost for the group of 9.3% on the 85% debt portion of TAPS capital. To date, ARCO's interest cost on its TAPS debt averages roughly 9%. Sohio's average interest cost slightly exceeds 10% per annum. As noted in the preface to this report, the TAPS tariffs employed in our models of prospective North Slope earnings reflect an initial capital cost of $6.8 billion ($8.0 billion, including construction interest) for capacity of 1.2 million barrels daily. This estimate

*In August 1975, Alyeska had raised its TAPS estimate to $6,375 million excluding provision for contingencies, up $395 million from 1974's $5,980 million (including $460 million for contingencies).

EVOLUTION OF TAPS COST ESTIMATES
FOR INITIAL PIPELINE CAPACITY*

(Billions of Dollars)

		TAPS Capital Cost plus Interest on Debt during Construction
December 1972		$2.9
December 1973		4.0
July 1974		7.0[a]
August 1975		7.5[b]
January 1976		$8.3
	Capital	7.0
	Interest	1.3

* 1.2 MM B/D
a. Included $460 million for contingencies.
b. Excluded provision for contingencies.

is based on data contained in company prospectuses issued after the August 1975 date of Alyeska's official estimate but prior to its recent revision to $7 billion.

The latest increase in TAPS capital and construction interest costs reduces integrated profits per barrel slightly below our estimate. Interest costs that prove higher than our assumed 9.3% per annum would have a similar impact (work in the same direction). Ceteris paribus (including the tariff on TAPS), Sohio's unit profit on TAPS will tend to be somewhat lower than ARCO's--on our earnings models--owing to its higher interest rate. On the other hand, Sohio will enjoy lower unit capital costs in the Prudhoe Bay field (more later).

We repeat the comment made in the preface to this report, that while our earnings models are based on below-actual costs of TAPS, we take the latest cost increase into account in our discussion of company financing of North Slope expenditures.

The increase in TAPS' estimated cost from $6.38 billion to $7 billion largely reflects lower-than-anticipated labor productivity. It is also worth noting that the preceding large increase in TAPS cost in August 1975 mainly represented the cost of catching up for pipeline delay in order to complete construction of the pipeline per se by October 1976, as originally scheduled. (Project completion for 1.2 million barrels daily, including pump stations and the Valdez terminal, is scheduled for July 1977.) The cost of catch-up on pipeline construction involved a greater application of resources--additional rigs to drill holes for the vertical support members for the above-ground half of the pipeline and additional pipeline spreads--rather than major revisions for inflation or wages.* Site preparation at the Valdez terminal has also proved much more costly than originally expected.

Unfortunately, Alyeska's latest cost estimate for TAPS cannot be regarded as definitive. Costs may well go still higher (see below). Possible utilization of much of Alyeska's 8,209 pieces of equipment, once TAPS is complete, to build a natural gas pipeline across Alaska would recoup several hundred million dollars, a welcome offset to potential escalation in TAPS cost.

Pipeline Construction Progress

Construction of the pipeline slipped behind schedule in the winter of 1974/75. A late 1974 start in work-camp construction, caused by delay in receiving environmental clearances, limited movement of men into the field to clear right-of-way, to build work pads (the 50-foot wide gravel strips along the 798-mile pipeline route), and to lay pipe. In addition, delayed delivery of specially-designed rigs to drill the holes required for the vertical support members (VSM's) for the above-ground half of the line pushed construction of the line behind schedule. The permit problem was resolved in the spring of 1975, and the number and rate of delivery of VSM drilling rigs was stepped up to target levels in the late summer of 1975.

By year-end 1975, the overall TAPS project was 41% completed but still short of the 45% goal set a year earlier. Construction of the pipeline itself (including clearing right-of-way, work pad construction, installation of above-ground pipeline supports, and pipeline installation) was 56% completed. Approximately 25% of construction on the pump stations and 28% on the Valdez marine terminal was completed.

On the pipeline portion of TAPS, work on some 700 miles of 50-foot wide gravel work pads--required to support heavy pipeline construction equipment and to protect the fragile permafrost from damage--was originally scheduled to begin in the fall of 1974 and to end in the spring of 1976. The mainline work pad was essentially completed by year-end 1975.

At the height of the summer-1975 construction season, 44 rigs were in operation for drilling holes for vertical support members. By year-end 1975,

*Virtually all materials for the pipeline have been ordered. Most contracts for materials provide for inflation between order and delivery dates "based on appropriate indices!" The current TAPS estimate still allows for 12%-15% inflation on materials. Most construction contracts provide for reimbursement of costs plus fixed fees. Wages are agreed upon through June 1976; they are estimated to increase 12% more in the third (presumably final) year of construction.

47,000 supports were set, and slurried in place, of the 78,000 required for the above-ground segments of the pipeline.

Full-scale pipelaying got underway only in late summer 1975. Nevertheless, by December, 370 miles of mainline pipe of the 798 miles required had been installed: 224 miles were laid underground, 145 miles on VSM's aboveground. Approximately 420 miles of mainline pipe will be elevated, and 380 miles will be installed underground. Each pipeline section will be tested with water upon its completion. By mid-November, when record cold and winds effectively shut down pipe installation and almost all welding, overall project construction was nearly a month ahead of schedule. Pipelaying per se was a bit behind schedule as winter closed in.

The Yukon River bridge--the one-half mile, $31.5-million connecting link between the northern and southern halves of the pipeline--was opened to 24-hour traffic in the first week of November 1975, two months ahead of schedule, despite an earlier delay due to inadequate piling for one of the four support piers. The timely completion of this permanent bridge assures all-season transport across the Yukon. Installation of the pipeline across the bridge is scheduled for the summer of 1976. Meanwhile, concrete footings have been poured for two other major suspension bridges, across the Tanana and Tazlina Rivers on the southern half of the pipeline.

Pump Stations Construction

Pump station and Valdez terminal construction schedules are programmed up to the second quarter of 1977, leaving no leeway for any major delay if the overall project is to be completed by mid-1977. However, to date pump station construction is on schedule. During the summer months of 1975, the main thrust of construction at the pump stations needed for the line's first operational months (Stations 1, 3, 4, 8 and 10) involved the pouring of foundations and erection of structural steel for permanent buildings, completion of crude and fuel tankage, and the beginning of main pump installation. All necessary pumps, turbines and generators are now in place, and the six main buildings required for operation at each station are essentially closed in. In addition to living quarters for the crew of technicians, a shop and warehouse building and structures were constructed for housing station controls, main pumps, booster pumps, turbines and manifolds. Station tankage, necessary for initial operation of the line, was also completed, with hydro-testing of the tanks scheduled to begin in the spring. Similar progress was made in building tanks and other facilities at Pump Station 5, which will be used initially only as a pressure relief station on the south side of the Brooks Range. Work on pump stations has continued at a high level despite the severity of the weather; the emphasis, however, has shifted to interior work--the installation of electrical and lighting systems, paneling for permanent buildings, of heating systems, and of ventilating systems for main turbines. Since installation of equipment will be carried out in winterized structures, any delay in pump station construction later on is not likely to be protracted.

Temporary construction work has been completed on the three stations (6, 9 and 12) which will raise line flow from 600 TB/D to 1,200 TB/D in late 1977. Work on permanent facilities at these sites is also underway, and will continue through the current winter.

Demobilization for winter has taken place at future stations (2, 7 and 11) which will eventually raise line capacity to 2,000 TB/D. During the early stages of operations, these will be operated as pass-through stations; no major equipment will be installed until the decision is made to increase pumping to the maximum level.

Another major undertaking has been construction of a natural gas line from Prudhoe Bay to Pump Station 4. Gas from the line will power turbine pumps at Stations 1, 2, 3 and 4. Approximately 6 miles of that 150-mile line have been completed after the start of construction on November 1.

Valdez Terminal Construction

The terminal site covers about 1,000 acres and includes crude storage tanks, docks, tanker loading and ballast water-treatment facilities, power plant and vapor control facilities, and other infrastructure.

As noted, the Valdez terminal project is also on a tight construction schedule; here again, "critical paths" in the sequential requirements of terminal construction have not been violated, although delays in delivery of materials to the site, limited road access, and an initial shortage of quarters slowed construction until well into 1975. Specifically, concrete tank rings for four 510,000-barrel storage tanks were completed on schedule, April 15, 1975. The first tank erection began at the Valdez terminal's east tank farm in May. Ten of the 14 tanks in the east tank farm were essentially completed by the close of 1975. Eventually 18 tanks will be built, but not all will be required for startup at 600 TB/D. Work is proceeding at various stages on the other tanks and on the oil containment walls that will surround the east tank farm. The initial 18 tanks will provide 8 days' supply of oil at a delivery rate of 1,200 TB/D. By the time the line reaches its 2 million barrel daily capacity, there could be up to 32 tanks. Site preparation at the west tank farm is also proceeding.

Three 432,000-barrel ballast water treatment tanks are basically completed. These facilities will be able to accommodate and treat, within 48 hours, the anticipated ballast from arriving tankers. Construction of two associated skimming tanks is essentially finished.

The foundation has been set and structural erection finished on the vapor recovery unit to which vented gas (released when crude storage tanks are being filled) will be withdrawn for reprocessing. The first inert-gas compressor has been set. The main steel structure of the power plant is largely completed and the large condensers for the three stream turbines and boilers have been erected. Additionally, significant progress has been made in trestle construction for tanker berth number four. In 1976, while berth four is being completed, work will begin on berth five. Berths one and three, completing the first phase of terminal construction, will be built in 1977. The berths are designed to accommodate tankers of over 150,000 tons. Turn-around time for the ships averages one to two days.

Labor Force on TAPS

At the height of the summer 1975 construction season the total work force on TAPS was 21,600. The 1975/76 winter work force was down by half. Winter weather virtually shut down pipelaying until spring. Emplacement of VSM's has continued but at a sharply curtailed rate. Preparations for construction of a natural gas line from the Prudhoe Bay field to the first four pump stations are accelerating. There has been no reduction in pump station manpower, and only a moderate cutback at the Valdez terminal. Remobilization of labor is now underway.

Tankers

The costs of large crude carriers built in American shipyards have risen from around $150-$200 per deadweight ton in 1970 to almost $500 a ton on current orders. Atlantic Richfield's tanker fleet for North Slope oil includes two 70,000 dwt tankers, three 120,000 tonners--all five delivered--and three 150,000 tonners (two firm orders, one option), for delivery in 1979-1980. The total tonnage comes to 950,000 dwt and our estimate of cost (including interest during construction), $393 million. Sohio's North Slope fleet, to transport its share of 1.2 million B/D of production includes two 80,000 tonners on long-term charter, two 120,000 tonners on firm orders, and six 165,000 dwt tankers ordered with various degrees of firmness for delivery in 1977-79. The fleet under construction aggregates some 1,230,000 deadweight tons; its total estimated cost will approximate $720 million including escalation provisions and interest during construction.*

Sources of Delay and Higher Costs on TAPS

Almost everything that could have gone wrong since commencement of construction of TAPS in the spring of 1974 has gone wrong--the exception being a major earthquake along the pipeline route or at Valdez. Each problem, however, has been manageable. The price of threatened delay is reflected in the recent major increases in the estimated cost of TAPS.

The factors mitigating against definitive estimates of cost and related completion dates, even at this late date, include: (1) the question as to the availability of skilled labor; (2) more worrisome, the uncertain productivity of labor and equipment under arctic conditions; (3) abnormal weather patterns; (4) the application of untried technology; (5) the possibility of mandated changes in design or construction for protection of the environment; (6) the associated possiblity of delays in obtaining construction approvals from regulatory authorities; and (7) unforeseen geologic or other conditions.

* The North Slope companies will lease, rather than own, their tankers for vessel life. The financing of tankers--involving complex and variable relationships among shipbuilding firm, chartering company, oil company and investment banker--is discussed in Chapter VII, NORTH SLOPE FINANCING.

Construction of TAPS has been plagued by labor unrest despite record wages and a no-strike agreement between Alyeska and the unions. The welders, in particular, have staged two major walkouts and their performance is reported to be spotty at best. Welding is probably the most basic yet vital aspect of building TAPS and is turning out also to be the most troublesome. The majority of pipe connections have used conventional stick-welding techniques except for several semi-automatic prototypes in limited use on the project. The welders union reportedly has vigorously opposed improved equipment and techniques. In August 1975, Alyeska authorized increased welding speeds for certain pipe welding operations after detailed testing. An average of 25% of manual welds have been rejected immediately (at times, 40%). In contrast, the reject rate for automatic shop welds is 5%.*

Despite all prescribed safeguards, quality control has been a source of embarrassment for Alyeska. In pipeline section three (a 150-mile stretch from the Yukon to 50 miles south of Fairbanks), an audit found that 247 welds of 3,748 completed required additional radiography and possible repair work either because of misinterpretation of X-ray results or procedural errors in radiographic examination.

As noted earlier, severe winter weather delayed construction of work camps and other progress in the winter of 1974/75 and record cold and snows brought pipeline activity to a near-standstill this past mid-November. In the fall of 1975, an unusual 4-inch rain in 2 days' time washed out two sections of the access road to the marine terminal site at Valdez. It also washed out part of the work pad in the southernmost pipeline section, causing rock and mud slides and temporarily closing a section of the Richardson Highway. Damage in both cases was quickly repaired and the tempo of construction accelerated to make up for lost time. The most outstanding examples of special weather-related construction modifications are the elevation of more than half the pipeline in areas of massive ice-permafrost soil conditions and heavy fiberglass insulation of the pipe in its elevated portions.

Construction of TAPS has also involved the application of significant new technology. Procedures for aboveground construction of a large-diameter pipeline (let alone one in arctic regions) have met with success. Prototype equipment has generally worked well but with some notable failures. Still, the most significant success is associated with adaptations to standard, simple equipment. Alyeska is employing some 8,200 pieces of equipment worth $300 million on construction of the pipeline.

Mandated changes in the pipeline route for environmental reasons have become routine. The pipeline will contain 800 animal crossings--about one per mile on average--some of which are designed to accommodate caribou migrations,

*According to Alyeska's quality control, every internal and external girth weld is X-rayed to detect hidden flaws and tested to assure hardness and impact resistance to 20 foot-lb. at -50^{o} Fahrenheit. The pipeline is designed to withstand an earthquake registering up to 8.5 on the Richter scale. It can withstand an axial force of 2.5 million lb. and lateral deflection force of 450,000 lb. before wrinkling.

ESTIMATED CAPITAL EXPENDITURES ON PRUDHOE BAY FIELD

(Billions of Dollars)

Development of Proved Reserves (9.5 bil. bbls.)

1969-1978: Oil Productive Capacity, 1,200 TB/D	$3.3
Increment to 1,500 TB/D	0.6
Subtotal	$3.9
Post 1978 Field Maintenance	3.0
Tertiary Recovery in Main Field[a]	3.0
Kuparuk/Lisburne Oil Development[a]	3.0
Gas Development[a]	2.0
Grand Total	$14.9

a. Speculative

Prudhoe Bay Costs and Facilities

Estimates of the capital cost of developing and producing the 9.5 billion barrels of proved crude reserves from the main (Sadlerochit) reservoir have ballooned in recent months. In fact, we are now witnessing something akin to the earlier horrendous escalation in pipeline costs. The estimated cost of developing the main field to an initial capacity of 1.2 million barrels daily will approximate $3.3 billion; expansion of capacity to 1.5 million B/D would raise the total to $3.9 billion. Even more astounding, post-1978 expenditures could exceed $3 billion, bringing the total capital cost of developing proved crude reserves to $7 billion (the same as the initial capital cost of TAPS), or almost 75¢ a barrel. The conventional wisdom had long placed expenditures for developing proved oil reserves in the main field at $2 billion, or 21¢ a barrel. These projected expenditures are apart from possible outlays on tertiary recovery, for development of Kuparuk/Lisburne reservoirs, or on expenditures for natural gas production (discussed later).

Initial development of the eastern half of the field where Atlantic Richfield is the operator (mainly for itself and Exxon) will greatly exceed expenditures on developing the western portion of the field, where BP is operator (for Standard Oil of Ohio). Sohio's expenditures associated with field capacity of 1.2 million B/D will approximate $1,260 million ($1,435 million in connection with capacity of 1.5-1.6 million B/D). In contrast, the capital costs of developing the eastern half of the field will approximate $2,040 million and $2,465 million, respectively. The disparity represents the encroachments of inflation upon the much slower rate of development adapted by ARCO during the long delay in obtaining approval for TAPS.* BP/Sohio proceeded more boldly.

Production of 1.2 million B/D from the main reservoir will eventually require completion of 130 development wells from 22 sites, with 6 to 8 directionally-drilled wells per site. Each pad will tap a subsurface area of 3,800 acres. At year-end 1975, 88 production wells had been drilled. Ten wells for gas re-injection are also being drilled. Production of 1.5 million B/D will require about 170 producing wells. Aside from development wells, the infrastructure for field capacity of 1,500 TB/D includes field pipeline systems, gathering centers, field fuel unit, gas compression plant, gas reinjection wells and power plant.

By early 1976, ARCO had completed 33 of 60 wells initially planned for pipeline startup in mid-1977; the company is operating 6 rigs to complete the initial development of the eastern portion of the Prudhoe Bay Field. ARCO shipped enough modules in the 1975 sealift to complete one of two initial flow stations in the eastern half of the field. In contrast to ARCO, Sohio's development program is further advanced; at year-end 1975, the company had drilled over 50 of 70 initial wells planned--all should be completed by early 1977. Sohio has also drilled 11 service wells which are presently suspended and reserved for future use. Sohio has shipped all components for two gathering centers to the Slope.

ARCO and Sohio are both constructing two gathering centers (flow stations), which together will handle 1.2 million B/D+ of crude. Two additional centers are scheduled for completion in mid-1978, raising gathering capacity to at least 1.8 million B/D. The latter facilities will be available for field expansion and standby use.

The approximate priorities for completing major components of Prudhoe development, beyond well completions and field gathering-pipeline systems, are: (1) the field fuel gas unit which will supply fuel to the power plant and first four pump stations on TAPS; (2) flow station module assembly; and (3) gas plant assembly.

Post-1978 Expenditures at Prudhoe Bay

Considerable confusion has arisen over the eventual total cost of developing the main reservoir's proved reserves of oil and also gas. Part of

*Capital expenditure estimates for ARCO and Sohio are presented and discussed in more detail in the section on financing. Costs of the power plant (Sohio's area of development) and of the gas compression plant (on ARCO's area of development) are being shared according to the tentative equities in the oil.

AGO 531524

the confusion is due to widely varying company estimates of post-1978 capital expenditures. The variability is understandable: (1) even approximate cost estimates must await operational experience, particularly reservoir behavior; (2) estimating the rate of inflation over a prolonged period is an exercise in speculation.* Additional confusion arises over the prospective allocation of costs between oil and gas. Clearly, a hefty portion (perhaps 40%) of capital expenditures incurred to bring field capacity to 1.5 million B/D, and which are necessarily assessed against oil at least until gas production begins, represents joint costs. These facilities include flow stations, gas compression plant, gas reinjection wells, and power plant. Another aggregation of costs, more directly attributable to gas, will arise once plans to produce the gas are developed. The latter include additional gas wells, possibly additional gas-plant capacity to compress the gas to pipeline standards, extraction of additional liquids from the gas, and intensification of waterflooding to replace the reservoir pressure lost through gas production.

Atlantic Richfield has estimated the cost of developing its share of the proved oil and gas reserves in the main Prudhoe Bay field through 1990 at approximately $2.5 billion. We tentatively assume that over 70%, or $1.8 billion of this total, may be allocated to oil (leaving $700 million attributable to facilities to be constructed once gas production is scheduled). ARCO estimates it will have spent $1,136 million on field development through 1978, leaving $664 million to be spent on oil development in the 1979-1990 period. On grossing up ARCO's share of oil-development expenditures after 1978, we find that total oil field expenditures would approximate $3,160 million. Total expenditures for 9.5 billion barrels over the life of the field sum to $7,192 million.**

In contrast, Sohio has ventured a guess that post-1978 spending of all companies on the main Prudhoe Bay oil field beyond the initial aggregate investment to reach 1,500 TB/D capacity could average $50-$100 million annually or $600 million-$1,200 million cumulatively through 1990. On Sohio's rough reckoning, the cost of developing 9.5 billion barrels of Prudhoe oil reserves will approximate $4,500-$5,100 million, a level of expenditures far below that extracted from ARCO's estimate.

A study published by the Department of the Interior in December 1975 cited the additional capital cost of developing and producing main reservoir oil at $8.2 billion (not counting $1.2 billion previously spent on field facilities) and $3.8 billion for additional facilities to develop and produce the gas. These estimates appear high even in comparison with ARCO's, owing to

---

* Post-1978 field facilities associated directly with oil include a waterflood and a gradual increase in the number of wells from 130 initially to 500-600 over the life of the field.

** Prospective expenditures directly attributable to gas gross up to $2.1 billion (ARCO's share $700 ÷ 33 1/3%).

the inclusion of estimated operating as well as capital costs in the totals. We surmise that ARCO's estimate of its share of oil and gas expenditures on the main reservoir allows generously for inflation and contingencies. Interior's estimates offer some clue as to the rough apportionment of expenditures between oil and gas.

Capital allowances in our models of Prudhoe Bay oil earnings (see Chapter V, EARNINGS MODELS OF NORTH SLOPE OIL) are based on company projections of cumulative spending through 1978 coupled with ARCO's projections for post-1978 outlays.

Tertiary Recovery

Prospects for tertiary recovery from the Prudhoe Bay field remain uncertain. We gather that injection of a miscible drive based on CO_2 extracted from the field's gas is technically feasible. Significant projects, employing miscible flood based on CO_2, are proving successful in the mid-continent area of the lower 48. There appears to be a difference of opinion among producers as to the adequacy of the CO_2 (16% of gas cap gas by volume) contained in the Prudhoe gas. The economics remain unproved; the total costs of such a project, the results measured in incremental reserves, and, of course, the market price of the added supply all remain elusive. Adoption by Alaska of the package of proposed tax changes would probably jeopardize such an undertaking. Previously, prospects for application of tertiary recovery at Prudhoe Bay appeared more promising. One of our earnings modles (designated the "production potential" case*) incorporates a tertiary recovery project; it allows for $3.0 billion for a miscible flood, employing CO_2 derived from natural gas, and for an increase in the main reservoir's recovery factor from roughly 40% or 9.5 billion barrels to an estimated 46% or 11.5 billion barrels. The incremental capital cost is assumed to be $1.50 per barrel. The latter numbers represent plausible guesses (we hope), rather than precise projections.

Kuparuk/Lisburne Reservoirs

Our estimate of the capital cost of developing the Kuparuk/Lisburne formations is also very tentative at best. We have assumed that capital cost averages $1.50 per barrel, owing to much lower well productivity than in the Sadlerochit (main) reservoir. ARCO expects that production of Kuparuk reserves would require water injection. Based on a production curve reflecting recent company speculation on peak production of 400 TB/D, we have derived a gross working estimate of $3 billion for the total capital cost of developing an assumed 2 billion barrels of oil from the Lisburne/Kuparuk formations.

Neither area has yet been declared commercial. Apparently 6 to 12 more exploratory wells will be necessary for a reliable initial definition of deposits in the scattered, shallow Kuparuk sands. However, the Kuparuk looks promising. Well productivity may approximate 2 TB/D. ARCO has completed

*See Chapter V, EARNINGS MODELS OF NORTH SLOPE OIL.

West Sak wells numbers 3, 5, and 6; numbers 1 and 2 will be completed soon. ARCO has suspended drilling in the Kuparuk area until the winter of 1976/77. Even less activity has taken place to date in the Lisburne formation; results, moreover, have been kept confidential owing to expected state leasing in the adjacent Beaufort Sea.

Outlook for Prudhoe Bay Costs and Completion

While the companies now have a good fix on development costs through 1978, some further moderate escalation would not be surprising. In fact, no escalation would be most surprising. Investors will have to live for years with great uncertainty over the eventual total cost of development--including maintenance of the main field, tertiary recovery, and commercialization of the Kuparuk/Lisburne reservoirs.

The 1975 barge shipment of production-facility modules critical to the initial development of the Prudhoe Bay field arrived at Prudhoe Bay in early autumn. Delivery of these most essential, large production-facility modules obviates reliance on the 1976 sea lift to have producing capacity of 600 TB/D ready by mid-1977. Accordingly, initial development of the Prudhoe Bay field at a production rate of 600,000 barrels of oil daily remains on schedule for mid-1977. Thirteen oceangoing tugs returned from Prudhoe Bay in October 1975 and will be available for the somewhat smaller sea lift planned for next summer. Nine lightering tugs remained. The prospective supply of barges is expected to be adequate although 25 remained at Prudhoe Bay. The planned increase of field capacity to 1.2 million barrels per day by late 1977 may be contingent upon a successful barge shipment during the summer of 1976. However, shipment of field equipment could be made by existing land and air routes if a major electrical unit were disassembled and transported in components. The odds, at least, favor clear sailing in the summer of 1976.

On a different note, another--but not major--risk has arisen in the form of trespass claims against non-Native land users on the North Slope. In April 1973, Federal District Court Judge Oliver Gasch ruled in the Edwardsen vs Morton suit that trespass actions could be initiated against non-Native users of Alaskan land before the Native Claims Settlement Act became law on December 18, 1971. Thus, any company or individual who occupied or used land claimed by the Natives is, according to Judge Gasch's opinion, subject to a potential lawsuit for trespass. And this is possible even if the company or individual held a valid federal permit to use the land. The judge held that the Native Claims Settlement Act of 1971 resolved who owned Alaska's aboriginal lands now, but it did not clear up settlement questions regarding prior damage; the court ordered the Justice and Interior Departments to draw up suits for trespass on 57 million acres on the North Slope.

In October 1975, Interior filed suit against 126 companies, including Alyeska, ARCO, BP and Exxon. The suit, filed on behalf of the Arctic Eskimos, asked that they be compensated for damage done to their aboriginal lands before the 1971 Act. The following (among others) are included as trespassory acts--utilization of the surface for airfields, buildings, roads and other structures; removal of sand or gravel; the taking of water; acquisition of valuable information regarding surface or subsurface resources; and extractions of oil or gas. Senator Ted Stevens of Alaska has proposed an amendment to the Alaska Native Claims Settlement Act of 1971 that would reaffirm the intent of Congress that the Act compensated for loss of Native-claimed land and that it extinguished all Native land claims. If he fails, the lawyers may do as well as the welders.

Scientists affiliated with the U.S. Geological Survey have warned that the massive, 425-square-mile Columbia Glacier jutting into Prince William Sound, just west of Valdez, may be on the verge of a drastic retreat that could discharge numerous icebergs into the shipping lanes of Prince William Sound--creating a hazard for oil tankers. Recent ice discharges reportedly suggest that the retreat may have started. If the glacier retreats from the shoals into the deeper water of the fjord, the rate of breakup and ice discharge could increase sharply just when crude shipments begin, and the problem could endure over an extended period. At present, this risk is nebulous. The companies could probably deal with the problem if it reached moderate proportions.

The most significant oil spill during construction occurred recently at Prudhoe Bay. Around 70,000 gallons of diesel spilled from a TAPS-owned storage tank when a sudden 50° F change in temperature caused an "overfull" tank to blow its lid. All but 2,000 gallons was contained by a dike; the bulk of the oil was pumped back into a storage tank. The remaining cleanup will follow in the spring.

CRUDE PRICE OUTLOOK

Introduction and Summary

This section is concerned with the institutional arrangements that will play decisive roles in governing the future level of crude oil prices in the United States. Clearly, the rational economics of petroleum as an internationally traded commodity is now dominated by these arrangements. We are, of course, concerned here with OPEC's pricing policies, and the constraints upon these policies, and with evolving national energy policy in the United States.

Prices on international oil flows are now established by the OPEC cartel; its ongoing commitment to continued escalation of crude prices is well known. Although the recently-enacted Energy Policy and Conservation Act now breaks the direct link with OPEC prices, OPEC pricing will clearly continue to set the ceiling on U.S. crude prices. OPEC has decisively withstood the test of adversity and, in our judgment, will remain essentially intact at least well into the 1980's. We therefore expect prices of OPEC crude to rise steadily, although perhaps moderately, over the medium term.

The new U.S. Energy Act extends price controls over a protracted period, rolls back "new" crude prices temporarily, provides for virtual recovery in the average price of the rollback in 1976, but does little else to clarify prospective price levels over the medium term. Projection of domestic crude prices will therefore entail supplemental judgments about political attitudes, election results, etc. We were relieved, however, to see that the final bill softened a provision in a working draft that would have required cost-related pricing for North Slope crude. Nonetheless, the bill, with its provision for inflation-based indexing and the special incentive increase in price, still smacks of cost-related pricing.

Unless the Congress proves unexpectedly generous in authorizing higher crude prices at home--and abandons its manifold objections to development of domestic energy supplies--dependence on imports will surely accelerate, giving renewed credence to the invincibility of the cartel and increasing economic pressure for higher domestic crude prices. If past is prologue, the cynic might then expect Congress to maintain a tight lid on domestic prices, the FEA Administrator's long-term pricing schedule (looking toward eventual decontrol) notwithstanding.

In sum, our conclusion remains that domestic crude prices will continue on relatively high ground, as compared with historical relationships to prices for other essential goods and services. We expect Congress will permit scheduled expiration of price controls only if the OPEC ceiling actually rises at a slower pace than we anticipate or, better yet, declines. For North Slope investors, of course, these favorable crude prices are clearly crucial to attractive earnings prospects. However, as we do not pretend to assess future levels of crude prices with perfect foresight, our models examine earnings possibilities for a range of crude prices, both above and below the recent level. Furthermore, recent tax developments in Alaska have reinforced our earlier conviction that the significance of crude prices per se for unit margins has become blurred by governmental proclivity to assess the "adequacy" of profit margins (translated: how little is enough?) and adjust taxes accordingly. In addition, the recent allusion at the federal level to cost-related pricing (shades of natural gas regulation) also reinforces our belief in the relevance of political "reasonableness" to earnings in each of our models.

The Critical Role of Government

The paramount issues of North Slope economics are, in our view, the two interdependent issues of crude prices and U.S. and Alaskan taxation. As we are now observing, rising prices do not necessarily imply commensurate increases in earnings. A safe, if unhappy, premise is that benefits from higher prices would accrue disproportionately to Alaska, and possibly the federal government, and that the penalty of sharply sinking prices would be borne disproportionately by the North Slope companies. Political entities, whether OPEC or Alaska, share similar biases; they will be assessing the "adequacy" of profit margins in relation to their own unquenchable thirst for oil revenues. Clearly, we do not mean to denigrate the importance of crude prices per se; obviously, higher prices are still preferable even under progressive tax regimes. Moreover, state tax collectors could confront contraints on their revenue-raising ambitions (more in the section on taxes).

A Glimpse Backward

In looking back only two years, we observe that domestic crude prices were benignly sheltered from the competitive pressures of the then lower-cost foreign crude by comprehensive import controls. Prices were then gravitating toward replacement cost as the drag on prices from surplus domestic producing capacity eased. On the West Coast, the "natural" market for North Slope crude, the widening imbalance between oil demand and local crude supply (the gap controlling permissible import volumes) portended ample accommodation of prospective North Slope production through displacement of imports. In that environment--where potential competition from foreign crude was constrained--were North Slope crude to move in limited quantity to the West Coast, its landed value would be established by the price of comparable domestic crude (taken as Signal Hill, 27° API gravity) on the West Coast. Once the market value of North Slope crude was thus established, the wellhead price would also be established, by the West Coast price less marine and pipeline transportation costs between the North Slope and the West Coast.*

*As a result, the wellhead price would vary with changes in market price or in the TAPS tariff (consisting of operating costs, interest charges, depreciation, state and federal taxes, and profits)--the lower the tariff, the higher the wellhead, and vice-versa.

Clearly, oil pricing, worldwide, has since become increasingly dominated by governments, with prices on international flows now established by the OPEC cartel. The United States has become a sub-sector of that international oil market. Once OPEC pricing no longer threatened to depress domestic prices, volumetric controls on imports were dismantled and reliance on imports accelerated. Accordingly, consuming nations have become relegated to the role of reluctant price takers, their control over the oil price mechanism limited to keeping prices of internal energy below OPEC-mandated levels (e.g., on controlled domestic crude), or to raising oil costs further (e.g., through import fees or tariffs). The response of the U.S. government has been to become ever more deeply involved in the price of energy fuels. For most of 1975, the United States simultaneously featured the lowest (for controlled crude) and highest (for exempt crude) prices among major Free World producers. Against this background, we examine trends in institutional arrangements governing the outlook for OPEC and domestic oil prices.

OPEC Pricing

The Current Environment

OPEC's overall steadfastness over the last eighteen months or so has been impressive, considering the sharp contraction in crude requirements over an unexpectedly long period--particularly for the heavy crudes--and Iraq's potentially disruptive drive for greatly increased market share. OPEC not only maintained a basically intact pricing structure, but even raised the general price level by approximately $1.00 per barrel in October 1975. It is true that erosion of prices from these higher levels has since occurred, but--with the apparent exception of Iraq--the reductions have been orderly and modest. In short, OPEC has encountered considerable downward pressure on market prices, disappointment in the slow pace of economic recovery in major markets, and a "spoiler" in its midst, but has withstood the test of adversity.

Owing to the sharp contraction in export demand--reflecting deep, worldwide recession, inventory depletion by importers, price elasticity, mild weather, and conservation measures--OPEC's crude production declined to 27.1 million barrels daily (MM B/D) in 1975, down 11.4% from the 30.6 MM B/D in 1974 and 17.6% below the pre-embargo level of 32.9 MM B/D in September 1973. At year-end 1975, OPEC's producing capacity amounted to 37 MM B/D. Of total surplus capacity of 10 MM B/D, some 7.3 MM B/D was located in the Middle East, with Saudi Arabia accounting for 3.3 MM B/D. In January 1976, OPEC production averaged 26.7 MM B/D, off 2.2% from the like 1975 period (and 1.8% below December 1975), offering no perceptible evidence of the expected cyclical recovery in aggregate demand in OECD markets. Demand for the heavier crudes (feedstocks for boiler fuels)--closely correlated to the pace of industrial production--has been particularly depressed. It is interesting to note that, while Iraq raised its 1975 production on average by 20%, its production dropped 13% in January 1976 (from 2,076 TB/D in December 1975 to 1,809 TB/D), due in part to competitive price cutting by other Gulf producers of heavy crudes. OPEC production was up smartley (+7.3%) in February 1976 to 28.1 MM B/D, the long-awaited beginning of recovery perhaps. Saudi Arabia's production rose strongly (+17.5%) to 7,940 TB/D. Iraq's production gained by a modest 3.1% over February 1975.

"Statesmanship" was the expected, almost inevitable, outcome of OPEC's conviction that volumetric setbacks would prove to be temporary and its awareness that the cost of competition would be incalculable, but enormous. OPEC is fully aware of the huge gap yawning between its own price level and the very low cost of producing still-abundant supplies of Middle East crude. At the same time, OPEC has been fortified by its perceptions of economic justice--including optimal pricing of its crude on a replacement-cost basis and maintenance of the purchasing power of its oil revenues.

The general increase in OPEC prices of last October was adopted when expectations of rapid recovery in the OECD economies ran high. The setting of price differentials to reflect relative crude values was to be taken up at a later date. The recession subsequently proved to be more enduring than earlier anticipated, exacerbating the problem of price differentials. In particular, asking prices for heavy crudes looked to be increasingly out of line, prompting companies to shift their liftings toward more attractive sources of supply. Squabbling among OPEC members over relative crude values intensified, leading to repeated postponements of a conference to settle the issue. Nevertheless, progress in reducing prices of overvalued crudes has been achieved through actions of individual nations--however reluctantly--in response to the offtake decisions of the major oil companies. Saudi Arabia, Kuwait, and, most recently, Iran have shaved prices of the heavier crudes from their October 1975 levels. On February 14, 1976, Iran reduced the price of its heavy crude by a token 9.5¢ per barrel to $11.40, although trade sources indicated that a greater reduction was warranted. Of course, strong recovery of production of heavy crudes ultimately must await parallel recovery in the OECD economies.

In sum, most of the major OPEC producers have accepted sharp reductions in production, tolerated Iraq's ambitions, maintained orderly markets, and minimized reductions in prices. Most importantly, Saudi Arabia has played the key role of "swing" producer (with the Aramco partners acting as informal surrogates), sopping up the largest part in market-dictated cuts in oil production among OPEC members. The impressive outcome of these developments is that, on average, the sales price of the principal OPEC crudes has moved higher, rather than lower, despite the most severe recession in major markets since the "Great Depression."

The Outlook for OPEC Pricing

The issue of OPEC pricing is most relevant for the potential market value of North Slope crude over the medium term--and, perhaps, through 1985. Investors are probably far less concerned over much longer-term trends in OPEC pricing. For one thing, progressive depletion of the low-cost reserves of the Middle East eventually and inevitably points to secular inflation in real energy costs worldwide--even when measured against the current price level imposed by OPEC. For another, investors will discount deeply the speculative character of truly long-term projections as also the distant realization of revenue and earnings. (Nevertheless, we would be hard put to pinpoint the year when Middle East supplies would no longer play the decisive role in worldwide pricing of crude.)

The complex issue of prospective pricing through 1985 hinges critically on the supply/demand balance for OPEC crude and the durability of the cartel. The issue could become increasingly intricate if political rather than purely economic forces more importantly dominate that balance. For example, present policies in major consuming nations regarding enlargement of indigenous supplies of energy--now generally half-hearted--could be modified. Further, OPEC itself, at least theoretically, could program the prospective supply/demand balance in international oil by fine-tuning its pricing and production policies. Specifically, OPEC could conceivably undermine new energy investments in consuming nations, aimed at heightened self-sufficiency, by manipulative pricing.* The test of a cartel is its degree of success in responding to market pressures or in manipulating those pressures by discrete, controlled alteration in the cartel's prices and volumes. Setting aside the issue of manipulative pricing for a moment, the key questions relating to OPEC's future reduce to (1) how burdensome might surplus capacity become over the medium term, and (2) if surplus capacity remains large and even grows, how might key members of OPEC respond to the pressures on volumes and revenues? To wit, would members submit to formal prorationing and severe constraints on prices if market pressures so dictate?

The Near-Term Outlook

For the immediate future, current pressures on OPEC are bound to ease as economic recovery in OECD nations progresses, however gradually. An improving economic environment facilitates agreement on price differentials and could even lead to another round of moderate price increases later in 1976. Although Saudi Arabia earlier stated its opposition to a 1976 increase in prices, experience suggests that it would once more go along with the majority. Saudi Arabia clearly prefers long-term accommodation on energy supply and prices to ongoing confrontation with oil-importing nations, in return for stable market arrangements, continuity in foreign investment and associated technological/managerial assistance. On the other hand, that nation has proven far less resistant to pressures for large price increases than its dominance in production and reserves, its strong financial position, and its professed foreign policy inclinations might suggest. Saudi Arabia has apparently chosen to navigate a cautious course through the tempestuous politics of the Middle East. Its indisputable,

*The U.S. proposal for a floor under international crude prices, adopted by the International Energy Agency at $7.00 a barrel, is intended to cushion the possible undermining of high-cost, internal energy investment whether triggered by accidental collapse or programmed reduction in the cartel's prices.

potential power as the balance wheel of OPEC production is thus notably offset by manifest political, demographic and military weaknesses. Saudi Arabia's delicate balance, nonetheless, will continue to have implications for market-sharing among OPEC members as well as for its posture on pricing (more below).

The Medium-Term Outlook

For perspective beyond 1976-77, it may prove useful to construct a hypothetical model of the supply/demand balance for OPEC crude, selecting an assessment which may be considered fairly pessimistic for OPEC. If we assume 4% per annum growth in free world crude demand, measured from 1975's depressed level to 1982 (only 2.5% a year measured from 1974's higher level), demand would rise from 42 million B/D in 1975 to 55 million B/D by 1982*.

This rate of growth is considered quite conservative, incorporating both a significant slowing in energy demand and accelerated development of non-oil energy sources (principally coal and nuclear). On the supply side, we postulate a generous flow of new oil production outside OPEC areas; we assume a potential recovery for declining North American crude production beginning in 1978 (including 2 million B/D from the North Slope, improved recovery of known reserves, and moderate exploration successes) plus a whopping 5 million B/D from the North Sea, and another 7 million B/D--much of this speculative--from non-OPEC sources outside North America. The foregoing demand/supply profile would have the effect of limiting OPEC production requirements in 1982 to approximately 32 million B/D, only modestly higher than 1974's 30.6 million B/D, and still below pre-embargo production levels. Obviously, OPEC's surplus producing capacity would remain large. Precisely how large it is impossible to project, since plans for developing productive capacity are currently being tailored somewhat to the realities of the marketplace. In this scenario, surplus productive capacity could conceivably remain close to today's 10 MM B/D, but this type of speculation can be overdone. The surplus in the ground is most important for the medium-term outlook; the pace of development by OPEC members will provide the clue for future production targets (after allowing for forecasting error) and prospective pressures on markets.

This "pessimistic" model points to no more than simple recovery in aggregate production to the pre-embargo level. Pressures on Saudi Arabia from hungrier nations (notably Iraq and Iran) to curtail drastically its growth in production would probably be intense. Brinkmanship could become the order of the day--Saudi Arabia could break the cartel, although in so doing invites retaliation. Open conflict, however, could potentially involve the superpowers and thus entail unpredictable results for all parties. Reason therefore suggests that security concerns and the "economic glue" that binds OPEC together will be sufficient to result in compromise rather than in confrontation. Yet miscalculation cannot be ruled out.

---

*Free world oil consumption expanded at 7.5% a year in the 1968-1973 period (+7.7% a year in the 1963-1973 period).

We have selected 1982 for our exercise because by then the bulk of production from known, large reserves found in recent years, which will preempt markets otherwise supplied by OPEC crude, will be on stream.

In our judgment, OPEC will most likely not confront an extreme test of its durability. It appears to us more probable that demand for OPEC crude will outstrip the "pessimistic" model, in view of the desultory commitment to conservation in many importing nations--especially our own--and the numerous obstacles to development of alternate energy supplies (and the long lead times involved), again most notably in the United States. The major oil-importing nations remain more committed to economic growth than to energy conservation.* Moreover, room for conservation within targets for economic growth is probably somewhat limited. Cumulative policies in the United States, regarding price controls taxes, possible divestiture, governmental power to act as sole buyer of oil imports, etc., all serve to foster growing dependence on imports and to buttress OPEC. If OPEC can moderate its price increases, it will reinforce complacency in importing nations. The case for moderation, as perceived by thoughtful analysts in OPEC, devolves on the importance of keeping one's major clients in a state of relatively good (financial) health.

It is also important to note that such important non-OPEC newcomers to production as Norway and Britain will have a self-serving bias towards high and rising prices. China, Mexico and the Soviet Union will also be content to sell crude at high prices.

On balance, then, we expect the cartel to endure. Prices of OPEC crude are therefore likely to rise at least through the early 1980's and probably well beyond. This thesis certainly holds for prices measured in current dollars; it may be less true for "real" prices. However, the current-dollar price of OPEC supply is the relevant price entering into the U.S. price matrix.

U.S. Oil Pricing Policy

Congress is today found more deeply involved than ever in the pricing of domestic crude and, beginning in 1977, in the pricing of North Slope as well (more below). The loose macroeconomic guidelines for pricing laid down by the Congress will find the FEA entrusted with extraordinary discretion over classifications of crude that can importantly affect the earning power of various categories and vintages of capital committed to petroleum resources.

While prescribing criteria for allowing higher prices for old oil, Congress has clearly suggested that the FEA retain the distinction between old and new crude in establishing pricing tiers. We can now only await, and speculate about, the FEA's coming judgements about incentives for different categories of production. Specific regulations governing pricing of Prudhoe Bay crude will not be formulated for many months and may first require supplemental legislation by Congress.

---

*We acknowledge that West Germany, much more effectively than the United States, has been most vigorous in moving to diversify its energy sources.

The recently-enacted Energy Policy and Conservation Act severs prices for "new" crude in the United States from OPEC levels at least for a time. The mandated rollback in the composite price of domestic crude to $7.66 a barrel finds new (upper-tier) crude prices rolled back to an average of $11.28 a barrel (with old or lower-tier crude prices remaining at an official $5.25 a barrel). The approximate rolled-back prices of a Prudhoe-type crude on the West Coast is $10.25 a barrel. In contrast, the current delivered cost of Saudi Arabian light, 34° API on the West Coast, is $12.70 a barrel ($11.80 per barrel for Arabian Heavy, 27° API). Of course, OPEC crude, so long as it is freely available, will continue to set the ceiling on the delivered price of North Slope crude on the West Coast. Below this ceiling, however, the Energy Act of 1975 provides the framework for assessing the outlook for prices on Prudhoe Bay crude at least over the next forty months (in effect from mid-1977 when North Slope production is scheduled to begin until mid-1979, two years later), and possibly over the next five years (through 1980).

Ironically, the very act of severing the link between new crude prices and OPEC levels will tend to reinforce the economic relevance of OPEC prices for U.S. pricing. The initial rollback in product prices, even if modest, will lead to increased demand. This, in turn, will lead to increased imports. U.S. pricing policy therefore will tend to (a) strengthen the position of OPEC and (b) undercut the efforts of the other industrial nations to curtail current oil demand, through a regime of high energy prices, and to reduce their dependence on OPEC imports in particular. The reluctance of Congress to sanction appreciably higher prices for natural gas will also translate into increased oil imports over time. Clearly, if any serious sentiment for raising U.S. self-sufficiency in energy fuels survives in the nation and in Congress, this Congress and its successors have a long road to travel.

Rollback in U.S. Crude Prices

It is worth briefly reviewing the pricing section of the Energy Act to gain perspective on Prudhoe Bay pricing prospects. As noted, the act mandates a roll-back in the composite "first sale" price to $7.66 a barrel. (The $7.66 a barrel target arises from the macroeconomic assumptions of 60% controlled crude, at $5.25 a barrel, and 40% "exempt" crude, revalued at the Senate's earlier target rollback to $11.28 ($0.6\times \$5.25 + 0.4\times \$11.28 = \$7.66$.) Under the rules which took effect February 1, 1976, the FEA will maintain a two-tier system for domestic crude oil production.* The new rules provide a formal definition of "old crude oil" as that volume produced and sold from a property in any month which is equal to the average monthly level of production during the calendar year 1975. (The previous measurement of old crude was production from a given property during the like month of 1972.) The altered FEA definition of old crude presumably

* While prescribing criteria for allowing higher prices for old oil following the initial rollback in the composite prices (more below), Congress clearly suggested that the FEA retain the distinction between old and new crude in establishing pricing tiers. Otherwise, a single pricing system would have required rollbacks in new crude prices of 40% or so; a single price system would also violate congressional intent to prevent the conferral of economic rents (called windfall profits by industry opponents) on older resources.

will require amendment to the Energy Act which established the average monthly production during September, October and November 1975 as the Base Production Level.

"First sale" price refers to "first transfer for value by the producer or royalty owner"--apparently, at or close to the wellhead. In inter-affiliate transfers, the first sale occurs at the same point as in arms-length sales. The "old"/"new" crude designations become lower and upper tier ceilings. Old crude prices remain unchanged, at least initially. Prices of existing new crude production are rolled back by $1.18 a barrel from the September 1975 level.* For prospective new crude production, the new (upper tier) crude ceiling is $11.28 a barrel for 1.7% sulphur, 34° API gravity, with upward and downward adjustments for differing gravity and sulphur contents. (To maintain proper historical perspective, it is worth emphasizing that the rollback in new crude prices is to the level of January 1975--and only temporary; the industry had come a long way by then.)

The $1.18 a barrel rollback to an $11.28-a-barrel new crude price follows from the FEA's estimate of exempt crude prices in September 1975 of $12.46 a barrel. The assumed implicit composite price before rollback (given macroeconomic assumptions of 60% controlled crude at $5.25 a barrel, and 40% "exempt" crude at $12.46 a barrel) was then estimated at $8.13 a barrel. The reduction in the industry's assumed composite price thus works out to $0.47 a barrel. For major integrated companies featuring, more typically, 70% old crude, 30% new, the rollback approximates $0.36 a barrel, or $7.42 (0.7 x $5.25 + 0.3 x $12.46) versus $7.06 (0.7 x $5.25 + 0.3 x $11.28).

In connection with the FEA's new rules on pricing, that agency has reopened for comment the issue of adjustments on gravity differentials for the heavy crudes of California and Alaska. A Prudhoe Bay type crude sold East of the Rockies would be priced approximately 15¢/barrel higher than on the West Coast, as a consequence of larger differentials per degree of API gravity structured into West Coast prices. The regional disparity in pricing of comparable crudes represents an historical penalty assessed against heavy crudes on the West Coast. Prior to full-scale development of sophisticated refinery processes for economically upgrading heavy fractions into lighter products in greater demand in West Coast markets, utilization of predominantly heavy crudes resulted in surplus refining of residual fuel oil which then had to be tankered into low-value export markets.

---

*For existing new crude production (under the new rules), the ceiling is the highest price realized on at least 25% of sales for each grade from that property in September 1975 minus $1.18 a barrel.

Provisions for Future Increases

in U.S. Crude Prices

Although the pricing section of the new Energy Act clarifies the outlook for domestic pricing and company realizations to some extent (for example, short-term expectations no longer include decontrol and a large jump in weighed-average crude price,nor an accompanying windfall profits tax with plowback credit for investments), the provisions for price escalation are so ambiguous and the FEA's discretion in structuring crude prices is sufficiently broad that one can project prospective crude prices only within a broad range.

The oil-price control authority in the Energy Bill ostensibly reverts to standby status at the end of 40 months and terminates after five years.*

Pricing provisions in the act differ considerably for the first year--the twelve months ending February 1977--than in the succeeding 28 months (before control authority reverts to standby status).

Escalation of the rolled-back composite price, for inflation and production incentive, may begin March 1, 1976. Starting March 1976 upward adjustments--not to exceed 10% in the first 12 months of coverage--are permitted for inflation (measured by the GNP deflator, adjusted to exclude OPEC effects) and to provide adequate incentive for development of high-cost and high-risk properties and for the application of enhanced recovery techniques to existing properties. The 10% "ceiling" includes a specified 3% production incentive, suggesting that the remaining 7% represents the increase for inflation (roughly based on recent experience). The President may propose adjustment in the incentive increase of 3% beginning three months after enactment of the bill, and every three months thereafter until early 1977. Either house may reject such proposal by a simple majority. Thus, the initial year's 10% increase in the composite crude price appears assured. A greater increase--based on an enlarged production incentive--may be proposed by the Administration but in our judgment is likely to be rejected by Congress.

Beyond the first year (i.e. after February 1977), the Energy Act makes possible wide departures from the implied 10% "ceiling" on annual increases in the composite crude price (see table on top of page II - 11). The FEA is expected shortly to issue a 39-month program for increases in crude prices which will incorporate increases in the composite crude price of 10% per annum. The price increases after February 1977 must be regarded as speculative. They are not mandated by legislature. It is even conceivable that the composite price may remain frozen after the initial year (1976). Even the inflation factor requires the President's sanction for its continuance. (Apparently Presidential approval of continuance of the inflation adjustment would not be subject to Congressional veto however.) The President must also approve the continuance of the 3% production incentive, but such approval is subject to veto by simple majority in either house. As noted, only an increase in the 3% production incentive is subject to Congressional veto in the first

*On signing the Energy Bill on December 22, 1975, President Ford simultaneously removed the $2-a-barrel import fee on crude.

ALTERNATIVE DOMESTIC CRUDE PRICE COMPOSITE:
YEAR-END 1975 - APRIL 1979

(Dollars Per Barrel)

	Worst Case	Favorable Case (+10% per year) Alaska Included	Alaska Excluded
Year-end 1975	$7.66	$7.66	$7.66
1976	8.43	8.43	8.43
1977	8.43	9.25	9.27
1978	8.43	10.12	10.20
April 1979	8.43	10.41	10.52

year of the Act. At the other extreme lies the possibility of greater than 10% annual price increases. Beginning in February 1977, and in succeeding Februaries, the President can propose an increase in the annual inflation allowance; this request must be justified to the Congress by an analysis of economic impacts and supply. This adjustment, too, may be blocked by either house. In the event of such disapproval, the President may submit one additional proposal, which could also be disapproved by either house.

It is not clear whether the composite price may be adjusted to reflect an annual inflation rate in excess of 7% (the implicit provision in the adjustment allowed in 1976), or in excess of 10% (the overall cap on the 1976 adjustment for inflation and production incentive that does not require Congressional approval). For example, if the President sanctioned continuance of both the inflation and incentive adjustments (and Congress did not veto the latter), would an adjusted deflator, of say 8%, result in an increase in the ceiling to 11%? Or would the 3% production incentive be effectively pared? If the deflator were 11%, would the current production incentive disappear, and a portion of the promised price adjustment related to inflation not be recouped in the composite crude price?

Clearly, the course of U.S. crude prices over the next 40 months will depend on the composition of the Congress, after the 1976 election, and on who will then be occupying the White House. One can hypothesize a variety of plausible political scenarios. Under a hostile Democratic President and Congress the average price of crude could remain at the February 1977 level--10% above the rollback price ($7.66 x 1.1 = $8.43/barrel), which would be close to the composite domestic crude price prior to the rollback. (Over time, of course, the composite price could still gradually increase, reflecting the growing contribution of new crude to total production.) In that unhappy event, the prior system of price controls, with the exempt categories responding to rising OPEC prices, would have been more rewarding to the companies (so much for the "compromise" characterization of the new Energy Act).

We would also speculate that a less unfriendly Democratic President could more readily obtain consent of a Democratic Congress to more generous increases (say, above 10%) than would a Republican President. (Prospects for election of a Republican Congress appear remote.) The table on page II - 12 sets out a plausible range of a composite domestic crude price.

HYPOTHETICAL STRUCTURES OF DOMESTIC CRUDE PRICES*

FEBRUARY 1976 - MAY 1979

(Dollars per Barrel)

	Unfavorable Composite Price [a]		
	Composite	Lower-Tier[b]	Upper-Tier
Feb. 1976	$7.66	$5.25	$11.28
Feb. 1977	8.43	5.51	12.38
Feb. 1978	8.85	5.65	12.25
Feb. 1979	9.29	5.79	12.28
May 1979	9.43	5.84	12.25
	Favorable Composite Price[c]		
	Composite	Lower-Tier[b]	Upper-Tier
Feb. 1976	7.66	5.25	11.28
Feb. 1977	8.43	5.51	12.38
Feb. 1978	9.27	5.79	12.97
Feb. 1979	10.20	6.08	13.70
May 1979	10.52	6.38	13.77

* North Slope crude excluded from the mix of old (lower-tier) and new (upper-tier) crudes.

a. Composite price rises 10% by Feb. 1977, and 5% per annum thereafter.

b. Lower-tier price permitted to rise at half the rate of increase reflected in composite prices.

c. Composite price rises 10% per annum over the 39-month period.

Even this limited range for average crude prices would lead to notably disparate earnings results. When we superimpose the extraordinary range possible between upper-tier (new) and lower-tier (old) prices within the composite, the potential spread in domestic crude prices becomes enormous. Beginning with an initial upper-tier price average of $11.28 a barrel and a lower-tier average of $5.25 a barrel, one can postulate numerous combinations within the constrained average in each year. (See the table above for two scenarios.) One can probably discard a scenario which merges the two-tier pricing structure into a single price over the next several years, unless permissible increases in the composite price were so large as to permit a large increase in the old-crude price average without squeezing new-crude prices. As noted, the Congress appears to favor continuance of the two-tier pricing system; while it is prepared to allow for incentive pricing on incremental supply, it strongly opposes "windfalls" on old reserves. The projected increase in the proportion of new crude to total domestic supply will also tend to constrain increases in old-crude prices if new-crude prices are to be maintained or to rise; again, the degree of constraint would depend on the flexibility of the composite ceiling. On the other hand, the FEA apparently wants to eliminate this market-distorting pricing system as soon as practicable, so one can anticipate some, if modest, provision for increases in old crude prices.

North Slope Crude Pricing

The President may propose a separate price ceiling for Alaskan oil in April 1977. Such ceiling may not exceed the highest average sale price permitted for significant volumes of any other category of domestic oil. (The original draft specified $11.28 per barrel, as adjusted by the GNP deflator.) The President must submit findings and the rationale which he believes to justify the separate ceiling price on Alaskan crude. The draft legislation required that this separate ceiling be based on findings concerning the cost of production--a disturbing step in the direction of cost-justified pricing. Equally disturbing, either house can still disapprove this separate ceiling.

It is not clear from the law whether the regulated "first sale" for Prudhoe Bay crude will be taken at the wellhead, at Valdez (the southern terminus of TAPS), or on the West Coast. Ostensibly, regulation of all domestic crude will be at (or very close to) the wellhead. If control is at the wellhead, then the law's constraint on Prudhoe pricing is meaningless even if we were to assume the unfavorable case in the preceding table (upper-tier price approximate to $12.25 per barrel by May 1979). The associated West Coast price for Prudhoe Bay crude works out to almost $17.35 a barrel (wellhead plus TAPS tariff plus tanker transportation: $12.25 + $4.60 + $0.50 = $17.35.) That price would be realizable only if the landed cost of imported supply, which sets the ceiling on Prudhoe crude in its major markets, were at least that high. (As noted earlier, Saudi Arabia light, 34^{o} API gravity now costs $12.70 a barrel delivered to the West Coast.) The import ceiling permitting, the approximate difference in delivered price of Prudhoe Bay versus upper-tier California crude would be $5.10 a barrel, in favor of Alaska.

This dilemma suggests to us that Congress may well legislate again on North Slope crude pricing before mid-1977. We speculate that the value of North Slope crude will then be set at least as high as other upper-tier domestic supply on the West Coast, but no higher.

In any event, it would seem sensible to assume that the higher the realization on North Slope crude the more likely is Alaska to pursue a steep excess profits tax.

Addendum: The FEA Acts on Crude Prices

After wrestling with competing arguments in the realms of equity and efficiency, the FEA has just issued regulations that establish guideline prices for domestic lower tier (old) and upper tier (new) crude for a 39-month period. The regulations are retroactive to March 1. The FEA has chosen to apply the immediately available increases--6.8% for the annual rate of inflation and 3% for the annual production incentive--on an equal percentage basis to lower and upper tier prices through September, 1977. Thereafter, lower tier prices will rise at a decreasing rate to permit upper tier prices to continue to escalate at a pace equal to or greater than the rate of inflation (in order to maintain incentives for exploration and development). In the final month of the present program (May of 1979), the rise in the upper tier price may have to fall below the inflation rate to avoid a reduction in the lower tier price.

The 6.8% rate of inflation utilized by the FEA was the implicit price deflator for the GNP in the fourth quarter of 1975. This rate is revised quarterly. The FEA will employ the first-quarter-1976 rate in its first revision of the crude price schedule. The schedule will be revised at least once every six months and will also take into account improved data on actual prices for crude in 1975 and early 1976, changes in the volume of old oil, and increases in new crude supply. Apart from the future rate of inflation, the upward slope of the price curves will also depend critically on whether Congress chooses to renew the production incentive in 1977, let alone to authorize a factor larger than 3%. In designing the schedule, the FEA has been concerned that the price of upper tier crude should never decline in real terms, while the price of lower tier crude should never decline in nominal terms.

Under the initial schedule, the price of lower tier crude will advance from its February 1 level of \$5.25 a barrel to \$6.16 by the end of the program; the price of upper tier crude will advance from \$11.28 to \$13.95. The composite price of crude, now \$7.66 a barrel, will reach \$10.38 a barrel by May 1979. This calculation allows for the contribution of upper tier crude to increase from its present 40% of total to 54%.

The FEA will issue special rules governing incentive pricing for production arising from enhanced recovery techniques by July 1.

The "base production level," required to establish the volume of new crude production from old fields, will be total 1975 output divided by 365. An adjustment to the base level for natural decline is now available, property by property. The recognized decline rate is 1972 output per day less 1975 output per day, divided by three. The basis for comparison will not roll forward each year, as earlier proposed by the FEA. On July 1, the FEA will permit the first adjustment for natural decline; it will be three-fourths of the actual average annual decline rate between 1972 and 1975. On January 1, 1977, and every six months thereafter, the base level will be reduced again for ongoing decline. This adjustment should reward past and present efforts to retard natural decline.

THE FEA'S PROJECTED PRICE SCHEDULE

(Dollars per Barrel)

	Lower Tier		Upper Tier	
	5/15/73 Posting Plus:	Estimated Price	9/30/75 Posting Less:	Estimated Price
Feb. 1976	$1.35	$5.25	$1.32	$11.28
Feb. 1977	1.74	5.64	0.47	12.13
			9/30/75 Posting Plus:	
Feb. 1978	2.12	6.02	0.23	12.83
Feb. 1979	2.23	6.13	1.14	13.74
May 1979	2.26	6.16	1.35	13.95

The increase in the composite price during the first year of the schedule will be 75 cents per barrel. This works out to approximately 1.8 cents per gallon; such change will be neither onerous, from the standpoint of inflationary pressures, nor much of a force for conservation. The more important force for rising product prices will be the growing volume of imports.

We recognize that the first revision of the schedule will probably feature an inflation rate below 6.8%, reflecting early 1976 experience. This would appear to dictate a downward shift of the schedule. Working in the other direction, however, will be belated recognition that the average price for lower tier crude is below $5.25 a barrel. We also deem it improbable that the FEA will be prepared to project the recently subdued rate of inflation into late 1976, let alone into 1979.

<u>The design of the FEA's price schedule strongly indicates that the price of North Slope crude will be established outside the national composite.</u> This may also be true for approaching production from the Naval Reserves.

We caution that the FEA's schedule will not be binding on whoever may occupy the White House in 1977. Hopefully, however, it would be difficult to gut a rational program in being.

The wide gap between the lower tier and upper tier price in May 1979--even with some escalation permitted for lower tier oil--drives home the improbability that Congress would then permit the decontrol of U.S. crude prices. The upper tier price in May 1979 is likely to be significantly below the laid-down cost of imported OPEC crude.

TAX ISSUES

Introduction and Summary

In this chapter we examine the critical tax issues that are relevant for North Slope prospects. In the United States, as abroad, "government take" has emerged as the largest component among the costs of integrated operations. With the proposed changes in Alaskan oil taxation, the government/company "profit" split approaches some foreign patterns. The windfall profits tax, long threatened but not enacted at the federal level, appears to be emerging forcefully in Alaska --and presumably without provision for plowback. Now that stringent price controls have been adopted at the federal level, a national windfall profits tax no longer warrants serious consideration.

As noted, the issues of crude prices and taxes have become virtually inseparable. We would feel hard put to translate crude prices, even if highly predictable, into after-tax earnings; proposed tax changes in Alaska suggest that ordinary assumptions about proportional changes in taxes and net income have become obsolete. Tax rates are becoming functions of price, worldwide, as taxing authorities (governments) reach into economic rents. Alaska appears to be ensuring that in the United States, as abroad, "progressive" tax policies can severely constrain the upside earnings potential implicit in high, or rising, crude prices. Future tax policies could exacerbate downside risk to earnings if governments also prescribe floors beneath anticipated oil tax revenues and disregard the downside implications of progressive schedules. floors

Alaska is surpassing even very pessimistic expectations of its probable long-term tax policies. The radical departure from state norm, implicit in the proposed excess-profits tax, could inaugurate an era of instability in federal-state tax sharing beyond Alaska's borders--with the companies squeezed uncomfortably in-between.

We, nonetheless, profess to optimism about the ultimate outcome of the emerging Alaskan tax debate--perhaps naively. The Alaskan tax changes outlined so far--though unwelcome and very poorly timed--would still leave the companies with "acceptable" unit margins. However, the issue of increased taxation on Alaskan oil and gas will not be settled once and for all time, whatever the fate of the initially proposed tax package.

FEDERAL TAXES

At the national level, OPEC's cartel pricing has proved a mixed blessing for oil companies: on the one hand, it has greatly enhanced the value of their domestic inventories in the ground; on the other hand, it has triggered stubborn Congressional resistance to decontrol of domestic crude prices, encouraged efforts to siphon off producers' "windfall gains," and has precipitated complex regulations hindering supply arrangements (allocations) and redistributing competitive advantage (entitlements). New tax legislation has eliminated the percentage depletion allowance for the majors, imposed potentially onerous taxation on foreign-source income, and may presage new regulations before long eliminating the expensing of intangible development costs for tax accounting.

So long as the Emergency Petroleum Allocation Act was due to expire as scheduled on August 31, 1975, Congress had little choice but to prepare to enact a windfall profits tax. Now that Congress has passed legislation limiting escalation of crude prices at least until the spring of 1979 (when controls revert to standby six months before expiring), the issue of a federal windfall profits tax has abated.

ALASKAN TAXES

Background

Alaska has been disturbingly quick to adopt radical changes in oil taxation when its prospective oil revenues appeared threatened (the 1972 tax legislation, since revised) or when budget deficits so required (the 1975 pre-production tax on Prudhoe oil reserves). We note that the issue of "Alaskan participation" arose once before, in 1972, when Alaska was concerned that the pipeline would emerge as the principal profit center. Alaska then sought complete control over the pipeline right-of-way (including the corridor on federal lands) and an undivided 20% interest in the pipeline, while proposing a steeply progressive tax on pipeline earnings and a minimum take at the wellhead from royalty and severance tax payments. It is now clear that, unless OPEC prices should crack (which we deem improbable) the wellhead will prove to be the principal profit center. (The increase in the West Coast price of "new crude," even as modified by the new energy legislation, will have more than compensated for the escalation of pipeline construction costs, as reflected in the TAPS tariff.) As its first option, Alaska has invariably chosen confrontation and the risk of litigation with the companies --who have not been unsympathetic to Alaska's financial concerns--rather than compromise.

To date, Alaska has had a vested interest in the highest feasible wellhead price for North Slope crude--the basis for calculating royalty and severance taxes which are the major sources of the State's projected oil revenues. It may be useful to review the 1972 confrontation in some detail. In 1972, the prospective wellhead price appeared to be under growing pressure, as the cost of TAPS spiralled upward. Given the (then) stable market price for North Slope crude on the West Coast, an increase in any cost component--marine and pipeline transportation, or in the field--inevitably portended reduced profits and reduced taxes. The locus of the cost increase--in TAPS--promised to be particularly damaging to wellhead price, hence to Alaska's prospective oil revenues, since the wellhead value is established by the market price for crude less marine costs and the TAPS tariff. Moreover, any increase in TAPS cost also increases pipeline profits under I.C.C. tariff construction. Thus, the wellhead price would be reduced by both the amount of cost and the allowable profit increase on TAPS. In short, Alaska became concerned that the pipeline would emerge as the principal North Slope profit center.

Thus, the Alaskan legislature, with the Governor's endorsement, enacted two laws in 1972 to avert such an eventuality. The thrust of the legislation was to persuade the companies to forgo the bulk of their profits on the pipeline (e.g., to post a low tariff) and thereby to raise the notional wellhead price. One law required Alyeska to negotiate the sale to the state of an undivided 20% interest in the pipeline; it also provided for the taxation of pipeline earnings at a steeply progressive rate (the weighted-average tax worked out to 31.5% of the 8% I.C.C. profits allowance). The second law arbitrarily established the state's minimum take from royalties and severance tax at the wellhead, based upon a wellhead price of $2.65 a barrel--a price then well above the indicated value of North Slope crude (after deduction of an artificially low TAPS tariff or even the deduction of the bare costs of a profitless pipeline).

Throughout the controversy, Alaska viewed the size of permissible TAPS profit as largely a "windfall profit," producing an unjustifiably high return on the equity capital committed to the pipeline. In our earnings models, clearly, a 7% return on the I.C.C. investment base (total invested capital, partially adjusted for inflation) translates into average annual returns of 113%-136% on the 15% equity portion of capital actually employed.* However, the permissible I.C.C. returns on average total capital employed average 15%-20%. Whatever the merits of Alaska's case versus I.C.C. regulation, it was clear that increased taxation on TAPS at the sole expense of TAPS owners would directly controvert regulatory practice on tariff construction for interstate pipelines.

Accordingly, the tax legislation enacted in mid-1972 raised a number of contentious issues which, if unresolved, would have lead to litigation and further delay in constructing TAPS. Since delay would have adversely affected the interests of all parties, and rising U.S. crude prices in 1973 mitigated concern over a cost-squeeze on state oil revenues, the companies and the state resolved their differences through a major revamping of oil tax legislation which became effective in January 1974.

Current Alaskan Taxation

Under the revised tax legislation of 1974, the direct attack on tariff construction through punitive taxation was abandoned. Instead, new property taxes were enacted at a rate of 2% per annum on net investment in TAPS (excluding capitalized construction interest) and a like 2% on exploration and producing properties. Annual property taxes were made payable prior to production startup, based on cumulative investment at the start of each construction year. The levy on TAPS property is recognized as a cost of service in the tariff. (We present in detail the growing pre-production payments on the North Slope project--including property taxes, the tax on reserves, as well as interest during construction--in the section on capital expenditures and company financing.)

Alaskan taxation at the wellhead currently combines features of the rescinded legislation of 1972 with more conventional previous levies. The present legislation has abandoned the concept of notional wellhead value and minimum royalty/severance tax. Once again, royalty is calculated separately from severance tax, whatever the wellhead crude price, and is maintained at 12½% of production, or the equivalent gross value. Prior to the 1972 legislation, severance tax--a levy on

*See Chapter IV, EARNINGS MODELS OF NORTH SLOPE OIL, page IV - 9 for table presenting earnings and rates of return on TAPS under alternative earnings models.

the gross value at wellhead (less royalty) of oil removed or sold--was a simple percentage of value, escalating with well productivity (see table below). As noted, the 1972 legislation fixed a minimum combined royalty/severance tax (50¢ a barrel) based upon an arbitrary wellhead of $2.65 a barrel. Were the indicated value at the wellhead to rise above $2.65 a barrel, then the previous schedule of severance tax would apply. Current legislation provides for alternate methods of calculating severance tax, with the higher of the two becoming the payable levy. The previous method--as a percentage of wellhead value, escalating with well productivity--is retained. However, the applicable tax schedule has been made more progressive. The alternative method establishes a cents per barrel levy (also escalating with well productivity), which varies in proportion to the BLS price index for crude petroleum.

When the current severance tax was framed in late 1973, the cents-per-barrel alternative promised to moderate the downside penalty to Alaskan oil revenue in the event of a precipitous decline in wellhead value that would attend a collapse of market price on the West Coast and/or--more likely--the TAPS tariff increased. At the lower wellhead value then indicated, the percentage and per-barrel severance taxes were about the same (24¢ a barrel). Subsequently, market price for crude soared, even compared to hefty increases in the estimated TAPS tariff, and the margin of percentage severance over per-barrel severance widened dramatically. In our earnings model designated the "reserves constraint" case, percentage severance in 1978 at a market crude price of $11.00 a barrel--wellhead of $5.90 a barrel--amounts to 46¢ a barrel. Per-barrel severance has increased to around 31¢ a barrel.

ALASKAN OIL SEVERANCE TAX*

CURRENT VERSUS PREVIOUS SCHEDULE

	Percent of Gross Value (less Royalty) at the Wellhead		
	Prior to mid-1972[a]		Effective 1974
Average Daily Production per Well		Average Daily Production per Well	
first 300 B/D	3%	first 300 B/D	5%
next 700 B/D	5	next 700 B/D	6
next 1500 B/D	6	over 1,000 B/D	8
in excess of 2500 B/D	8		
Weighted Average[b]	7.34%		7.77%

* Gross Production Tax.

a. Operative also under short-lived 1972 tax legislation when wellhead price exceeded $2.65 a barrel; for lower wellhead prices, the 1972 tax legislation set a minimum royalty/severance tax of 50¢ a barrel.

b. Assuming well productivity of 10,000 B/D.

Additional legislation, recently enacted to close anticipated state budget deficits, introduced a two-year (1976 and 1977) tax on Prudhoe Bay oil reserves. Since this tax was designed to yield pre-determined revenues, the tax formula itself is of secondary importance. For 1976 and 1977, a 2% tax is imposed on the "value" of Prudhoe reserves. The reserves tax will presumably be credited against company severance tax payments in 1978-79. (The hefty increase being proposed for the severance tax--discussed below--represents a back-door reneging on Alaska's earlier promise to repay the reserves tax.) For the two-year period 1976-77, the temporary tax on Prudhoe Bay oil reserves will add approximately $120 million to ARCO's capital expenditures on the North Slope project, and $260 million to Sohio's.

Under current tax legislation, Alaska retains a vested interest in attaining the lowest feasible tariff on TAPS and the highest possible wellhead price. The state is likely to exert every possible pressure on TAPS owners to post tariffs somewhat below the I.C.C.'s permissible maximum. (As discussed in a later section, our earnings models allow for below-maximum profits on TAPS.) However, possible changes in the principles governing I.C.C. tariff construction are not so remote as it previously appeared. Basic issues in pipeline ownership and regulation are even now being scrutinized in Congress.

Proposed Tax Changes in Alaska

The Alaskan legislature has begun deliberating a package of tax proposals designed to sharply (300%) increase the state's anticipated tax revenues from the Prudhoe Bay field, from an estimated $5 billion to $20 billion*. (Competing proposals would raise the state's take even more.) These revenues will be apart from the state's royalty interest (12½%) in oil and gas production. The proposals encompass a major increase in the severance tax, a modification of the corporate income tax structure, and the introduction of a steep excess-profits tax.

The severance tax would rise from an average 7.8% of wellhead value to 12.6%, by the addition of two more steps in the schedule, which escalates with well productivity. Two steps would also be added to the minimum cents-per-barrel severance tax: $0.77 on 1,000-2,000 B/D and $1.015 a barrel on well production over 3,000 B/D. (See table on next page.)

*The oil and gas tax proposals emerged from the deliberation of the Alaskan Senate's Special Interim Committee on Taxation and Revenue, chaired by Senator John Huber. The Alaskan legislature, which reconvened January 19, 1976, limits its sessions to a few months; appointment of a spec[illegible]l committee to investigate and propose legislation on particular issues is a freq[illegible]ent practice.

ALASKAN OIL SEVERANCE TAX*

PROPOSED VERSUS CURRENT SCHEDULE

(Percent of Gross Value, less Royalty, at the Wellhead)

Current Average Daily Production Per Well		Proposed January 1976 Average Daily Production Per Well	
first 300 B/D	5%	first 300 B/D	5%
next 700 B/D	6	next 700 B/D	6
over 1,000 B/D	8	next 1,000 B/D	8
		next 1,000 B/D	11
		over 3,000 B/D	14.5
Weighted Average	7.77%	Weighted Average	12.62%

*Gross Production Tax.

Alaska's 9.36% corporate tax rate will be transformed into a "net proceeds" tax when applied to oil and gas income. The state is concerned that a portion of income on Alaskan oil and gas, which actually will arise upon their sale beyond Alaska's borders, should be imputed to Alaska--in short, that Alaska be recognized as a profit center as well as a cost center. At this juncture, we can only speculate that the computation of "net proceeds" for corporate tax purposes will involve levels of transfer prices at Valdez (and at the wellhead); it will certainly limit allowable cost deductions (e.g., allocation of a portion of corporate overhead to Alaska).

The third, and most radical, element in the tax package is an excess value (windfall) tax. The excess value tax, apparently to be a flat 41%, would apply to the difference between the market value of North Slope oil f.o.b. the West Coast and a variable deemed value. (References to a 50% take, which we have seen in the literature, include the state income tax of 9.36%.) The Senate bill specifies a deemed value of $7.00 per barrel as of the date of passage of the bill, but allows for subsequent escalation with the wholesale price index. The bill does not provide for tax credits for investment in Alaskan oil and gas exploration/development (i.e., for plowback).

The Special Committee's tax proposals are too hazy and so obviously subject to substantial revision to allow for definitive estimation of their impact on the companies' earnings prospects. The essential point is that the Alaskan legislature will be concerning itself principally with the timing and mechanics of how best (not whether) to extract a healthy share of prospective economic rents on North Slope oil and gas. The incidence of an excess-profits tax cannot be shifted, because the matrix of crude values in the lower 48 states will be a datum to North Slope operators. Alaska would be taxing an economic rent, and taxing it severely.

The thrust of the excess-profits tax mechanism appears to be to permit the North Slope companies to recover their capital and operating costs (including severance tax) and to make at least $1.00 a barrel, pre-tax, before the bite of state income, state excess value, and federal income taxes. It is important to note that the "assured" $1 margin would be on the deemed value--to be read, just price--for Prudhoe Bay crude.

In subsequent sections concerned with industry and company earnings possibilities in Alaska, we examine the impact of a flat excess-profits tax (at the suggested rate of 41%) in detail.* We note, in advance, that Alaska's share of production income would be appreciably larger than that accruing either to the Federal Treasury or to the North Slope operators.

At least two critical, nagging questions are at once relevant for the dynamics of the earnings models: (1) Will the escalation of the deemed value proceed pari passu with the sanctioned (or market-determined) value of comparable crude on the West Coast (or in the Midwest)? (2) Will the initial flat rate remain unchanged over time, shift upward periodically in quantum jumps, or evolve into a progressive tax on windfall realizations (as now applies for Dutch gas and for large operators--to be read, Caltex--in Indonesia)?** The answers are interdependent in their investment implications. For example, reasonably parallel escalation and a flat tax rate would permit investors' (i.e., operators' and shareholders') expectations about unit profits to be restored, after a lag, courtesy of the FEA, the market, and/or OPEC. Alas, these assumptions may be overly optimistic.

Comments on Proposed Taxes in Alaska

We are not shocked that Alaska wants and intends to get more of the widening profit margins on North Slope oil. However, we are disturbed that "responsible" Alaskan legislators are seeking so much more of the economic rents, and by the radical route chosen to acquire that incremental revenue.*** In effect, Alaska may be prepared to prescribe a "just price" for North Slope crude on the West Coast. We presume that the tax committees of the legislature would eventually prescribe a just price for natural gas as well. Unfortunately, the notion of a just price is really not far removed from an a priori assessment of what constitutes an "adequate" (ceiling) per-barrel profit margin (in dollars and cents). In short, investors will and should worry that a excess-profits tax can be easily transformed into a steeply progressive one.

Owing to the indicated appreciable increase in tax-paid costs for Prudhoe Bay crude, the viability of North Slope production becomes even more sensitive to any significant reduction in OPEC prices. Ironically, the thrust of both U.S. and Alaskan oil policies will tend to bolster OPEC,**** thus lessening the risk of a

---

* See Chapter IV, EARNINGS MODELS OF NORTH SLOPE OIL, and Chapter V, COMPANY EARNINGS ON NORTH SLOPE OIL.

** The Huber Committee explored the possibility of introducing a progressive tax, but opted for a flat tax in the proposed legislation.

*** Preoccupation with the excess value tax can lead one easily to overlook just how substantial is the proposed increase in the "conventional" severance tax as well.

**** By raising demand (U.S.) and dampening incentive (Alaska).

major decline in international oil prices.

It is disturbing that Alaska appears to believe that, like Norway and the United Kingdom, it is entitled to tax away for its own needs a substantial portion of a windfall gain that has resulted from OPEC's pricing power. On the other hand, the analogy cannot be pushed too far. Britain and Norway have both continued to exhibit a decent respect for maintaining investment incentive, particularly with regard to rapid recovery of investments. Moreover, these are sovereign nations and their oil-taxing policy is integrated with national energy policies. In contrast, Alaska would appear to be flouting the goals of emergent U.S. energy policy. A hostile Congress has sanctioned incentive prices for incoming supply at difficult frontiers.

Alaska's perceptions may well be compared to those of many of the OPEC nations. The oil and gas will be leaving Alaska and the economic benefits conferred by these hydrocarbons will be realized by the "importing states." In contrast, Texas, Louisiana, California and other producing states have enjoyed a surge of economic development within their own borders on exploiting indigenous resources. Alaska will probably never enjoy the economic and social benefits attending major investments in refineries and petrochemical plants. (It will also be spared the social costs, such as pollution, attending these same investments.) Alaska also appears to regard the North Slope companies--industry giants--as "foreign" entities, as through OPEC's perspective. In older producing states, the small local company represents an important political and economic constituent.

Economic returns from North Slope resources that could be applied for exploration and development in Alaska, off the West Coast and off the Atlantic Coast, or applied for investment in enhanced recovery techniques or in "synthetic" energy fuels would, instead, go to fund social services in Alaska. Alaska appears prepared to seek to maximize its take from the presently proved reserves on the North Slope. The state would appear to be disregarding the disincentive it is creating for probing for additional reserves, onshore or offshore, on state leases. It may well be irrational--from the standpoint of return on capital--for the companies to drill in the Beaufort Sea, or for ARCO to continue exploration west of Prudhoe Bay. Should the excess profits tax apply only to Prudhoe Bay (i.e., to giant fields), such discrimination is not likely to be especially reassuring to other operators (whose dream is to locate "another North Slope").

Not surprisingly, then, the producers and Alaska are once again found in an adversary position. Considerations of national energy policy may before long find the Federal Government and Alaska in an adversary relationship as well. The $7 base price runs counter to the intent of national economic policy. Let us assume that with plausible escalation the base price is now not much more than the February 1 national composite of $7.66 a barrel. However, Congress has not prescribed a rollback in the benchmark price for new crude to $7.66 a barrel; the rollback has been to $11.28. As noted, Congress would permit producers of new crude at difficult frontiers to earn a superior return. One may call this incentive pricing and/or a reward for risk-taking. Alaska would take a large bite of this back.

It may also be noted that the windfall profits tax, formulated by the U.S. Senate Finance Committee before enactment of the December 1975 energy bill (controlling prices), was to apply to old oil under control and then-exempt crude selling above \$11.50 per barrel. Moreover, the base price was to gradually rise while the amount subject to tax would gradually decline. The tax was to "fade away" after a 67-month period. Plowback was to be limited to 25% of tax liability; the credit would be dollar-for-dollar for eligible investments. These investments included intangible drilling costs, geological and geophysical expenses, depreciable production equipment, outlays for gathering lines, and operating expenses for secondary and tertiary recovery. It is worth recalling that North Slope oil would probably have escaped payment of the bulk--probably all--of any windfall tax, owing to (1) the relatively low wellhead price for Prudhoe Bay oil after deducting high transportation costs; and (2) the rising price for determining windfall.

Conjecturally, the conflicting claims between the federal government and Alaska could encompass other states as well and would clearly be bearish for the entire U.S. petroleum industry. One can study the unfortunate position of the Canadian petroleum industry as Canada's Provinces and its Federal Government clash over shares in revenues. Periodically, the principal actors in Canada recall that the producers should be assured "adequate" returns.

The timing of the Alaskan proposals is unfortunate. It comes when the companies are concerned with completing financing arrangements for bringing North Slope oil to market and when the FPC has just voided the advance-payments program for much of the North Slope gas. Fortunately, the bulk of debt financing for TAPS has been completed. Financing of development expenditures is also well advanced.* From the standpoint of future requirements for external financing, there is no denying that the economic value of the operators' principal collateral--their net profits interest in the crude--has even now been diminished. We presume that the state is preoccupied with firming up its own revenue expectations in order to facilitate borrowing for its internal needs.

We profess to optimism about the ultimate outcome, perhaps naively, because we would like to believe that state and national policies will recognize the case for rewarding exploration effort at difficult frontiers. To be sure, the companies are in a poor bargaining position today, as compared with 1972. The pipeline was then a concept. Today, the principal costs for transportation are sunk or firmly committed. Development of production facilities is well underway. The price of North Slope crude, on the West Coast or in the Midwest, will be governed by FEA ceilings (or one determined by Congress) for the initial years of production, and probably longer. As already noted, given such legal and/or market constraints, the incidence of an excess-profits tax cannot be shifted.

There is some comfort in reports that many Alaskan officials were surprised at--and perhaps a bit chagrined by--the tax package unwrapped by the Special Committee. Legislators may find it difficult voting against \$20 billion in state revenue in favor of, say, \$10 billion. Governor Hammond regrets the timing of the tax proposals but has not declared an intention to veto any of the legislation if

*See Chapter VII, NORTH SLOPE FINANCING.

passed. Alaskan Natives' corporations, so anxious to attract oil-company investment in the evaluation of extensive acreage holdings, may present the strongest Alaskan opposition to the oil tax proposals. They are not enamoured of informal suggestions to single out prospective oil acreage owned by Alaskan natives for special exemption from some elements in the proposed tax package.

Because of the companies' weak bargaining position in Alaska, they may have no other recourse but to seek redress in the Federal courts. We do not pretend to be experts at constitutional law. We anticipate, however that a constitutional issue may be raised about the taxing of an economic value that arises beyond the state border, in the stream of interstate commerce. The companies may also allege that by creating a disincentive for further exploration effort, the excess-profits tax creates an undue restraint upon normal trade among the states. It is clear that the framers of the proposed tax changes took particular care to avoid effective legal challenges to the legislation. Congress and the Administration may choose to exert pressure on behalf of the companies also. As a developing state, Alaska is not immune to the lure of proferred federal largesse or indifferent to its denial (as constrained by law). Such pressure is most likely to be exerted if requested by the FEA or by other producing states; political realities militate against Congress responding directly to the oil companies' appeal. Equity for oil companies and their shareholders is no more attractive an issue in the Congress than in the Alaskan legislature.

EARNINGS MODELS OF NORTH SLOPE OIL

Introduction and Summary

We have constructed three models of earnings of North Slope oil--designated the "production potential," "reserves constraint," and "market constraint" cases--which we describe and analyze in this chapter. Our earnings models are differentiated as to reserve assumptions, peak production levels, and rates of production build-up. Results are expressed in terms of earnings per barrel on TAPS, main field production, and Kuparuk/Lisburne production. Under each model, the earnings possibilities will, of course, vary substantially according to assumptions regarding market values for crude over time and tax policies--notably in Alaska.

The "reserves constraint" model features production from only the 9.5 billion barrels of proved oil reserves in the main Prudhoe Bay field. Production is assumed to build up rapidly to a 1.5-million-barrel-a-day peak by 1979. The "production potential" model features production from the three Prudhoe Bay reservoirs--the Sadlerochit, Kuparuk and Lisburne formations--with assumed reserves of 13.5 billion barrels. Production builds to a peak of 2 million barrels daily by 1984. Our "market constraint" model also allows for production from all three reservoirs but production rises more slowly and reaches a peak of only 1.5 million barrels daily by 1981.

Representative earnings per barrel on combined pipeline and producing operations, given the approaching market value for Prudhoe-type crude of $11.00 per barrel and existing tax law, would approximate $3.20 per barrel (roughly $1.00 on TAPS and $2.20 at the wellhead). For an expectable market value for crude of $13.00 a barrel, integrated earnings would approximate $4.10 per barrel. Proposed changes in Alaskan tax law would reduce integrated earnings, under the $11.00-a-barrel assumption of market value, from roughly $3.20 to $2.50 per barrel, and under a $13.00-a-barrel assumption of market value from $4.10 to around $3.20 per barrel.

As expected, the contrast between returns on TAPS versus those on production is striking. We estimate the DCF rate of return on TAPS at 10%. Returns on oil production--under current tax laws--approximate 23%, given a crude price of $11.00 per barrel, and 27% if the crude price were $13.00 per barrel. The contrast between returns on production under current tax legislation versus returns arising under Alaska's proposed legislation is also noteworthy. Proposed Alaskan taxation would reduce returns on the field from 23% to 17.5% (assuming $11.00 per barrel for crude), and from 27% to 21.5% (assuming $13.00 for crude). Upon combining investment and cash flow stream for TAPS and production, the integrated return--under present tax laws--approximate 14%, assuming $11.00 per barrel for crude on the West Coast, and 17% given a $13.00-per-barrel price. Comparable returns under proposed tax changes would be 12% and 14%, respectively. In the current debate over Alaskan tax policy, the state is focusing on prospective returns on production. The companies, understandably, are emphasizing the total project rate of return.

The translation of the industry models and Alaskan tax proposals into per share results for ARCO and Sohio is the subject of the next chapter.

THE MODELS

"Reserves Constraint" Case

The "reserves constraint" case features production from only the 9.5 billion barrels of proved oil reserves in the main Prudhoe Bay field. Production is assumed to build up rapidly to a 1,500 thousand-barrel-a-day (TB/D) peak by 1979; that rate of production would be sustainable with water pressure maintenance for 6 to 8 years and would thereafter decline to approximately 1,000 TB/D by 1990. This represents the conventional model of North Slope oil production with the life of the main field assumed to be 25 years. Despite its shortcomings (see below), the model is worthy of attention--it isolates the most definitive component of North Slope production, the main reservoir. Moreover, the cost estimates in this "reserves constraint" model correlate with proved reserves estimates appearing in company prospectuses. This model will obviously translate into lower earnings for the North Slope companies than models which assume a broader production base on two accounts--lower production and pipeline throughput volumes, and lower unit earnings on integrated operations owing to assumed underutilization of TAPS. We note that the disincentive aspects of pending Alaskan tax proposals may well require emphasis upon conservative estimates of future production.

"Production Potential" Case

The "production potential" case features production from the three Prudhoe Bay reservoirs--the Sadlerochit, Kuparuk and Lisburne formations. Portions of the latter two deposits overlap with the main (Sadlerochit) reservoir. This model incorporates estimated production from the 9.5 billion barrels of proved oil reserves (our "reserves constraint" model) with highly tentative estimates of potential production from tertiary recovery in the Sadlerochit reservoir and the somewhat more assured production potential from the lesser Kuparuk and Lisburne formations.

In our "production potential" model, Sadlerochit production is assumed to build up to 1,600 TB/D by 1981: 1,500 TB/D is supportable by currently proved reserves; the assumption of an additional 100 TB/D is supported by 2.0 billion barrels of speculative reserves from eventual tertiary recovery. Incremental production from tertiary "reserves" is limited to allow for a build-up of Kuparuk/Lisburne production within the constraints of pipeline capacity--these estimates assume production beginning in 1980 and building to a peak of 400 TB/D by 1984. The tentative construction of a production profile over a 25-year reservoir life with peak production of 400 TB/D for eight years yields an estimate of Kuparuk/Lisburne reserves of some 2 billion barrels. Reserves produced from all three reservoirs over the life of production would yield 13.5 billion barrels.

Measurements at this time of the effort (in terms of investment and operating costs) and results (reserves added) of tertiary recovery and exploration of the Kuparuk/Lisburne areas are necessarily speculative. This is particularly true of tertiary recovery, although our assumptions appear conservative when compared with more authoritative speculation in the past. While technical conditions for tertiary recovery are promising, the economic parameters are in flux, and the companies are thus cautious about projecting prospects. Alaska's reconsideration of its taxation of oil and gas production will reinforce this wariness--understandably so. The assumed contribution of the Kuparuk/Lisburne formations is loosely based on a past

ALTERNATIVE TAPS THROUGHPUTS
AND PRODUCTION PROFILES OF NORTH SLOPE RESERVOIRS,
SELECTED YEARS

(Thousands of Barrels Daily)

	"Reserves Constraint" Case	"Production Potential" Case	"Market Constraint" Case
July-Dec.	TAPS Throughput		
1977	600	600	600
Year			
1978	1,200	1,200	1,200
1979	1,500	1,500	1,200
1980	1,500	1,550	1,200
1981	1,500	1,750	1,500
1982	1,500	1,900	1,500
1983	1,500	1,950	1,500
1984	1,500	2,000	1,500
1990	1,045	1,960	1,500
July-Dec.	Production Profiles of Main Prudhoe Reservoir		
1977	600	600	600
Year			
1978	1,200	1,200	1,200
1979	1,500	1,500	1,200
1980	1,500	1,500	1,160
1981	1,500	1,600	1,200
1982	1,500	1,600	1,200
1983	1,500	1,600	1,200
1984	1,500	1,600	1,200
1990	1,043	1,600	1,200
	Speculative Production Profiles: Kuparuk/Lisburne Formations		
1977-79	...	...	...
1980	...	50	40
1981	...	150	300
1982	...	300	300
1983	...	350	300
1984	...	400	300
1990	...	360	300

ARCO submission to Congress. The 400 TB/D estimate may, however, prove conservative.

"Market Constraint" Case

Our "market constraint" case, like our "production potential" case, allows for production from all three Prudhoe Bay reservoirs but assumes that market limitations constrain the pace and extent of production buildup and the utilization of productive capacity. This case could also represent a "pipeline constraint" model in the event that future discoveries on the North Slope (on Naval Petroleum Reserve Number 4, for example) were to require Prudhoe Bay producers to relinquish some share of TAPS total throughput. Production rises more slowly than in the two preceding cases--to a 1,500 TB/D peak in 1981--but is maintained at that level over a more prolonged period. Production from the Sadlerochit reservoir alone fulfills assumed market requirements until 1980, rising to a peak of 1,200 TB/D in 1978. Kuparuk/Lisburne production is assumed to begin in 1980 and to rise to a peak of 300 TB/D by 1984. Respective shares of total production are maintained constant over most of the remaining life of the field. Reserves produced over the estimated 25-year life of the field would total 13 billion barrels. While prorationing to market demand would appear unlikely (except perhaps in the event of weakness in worldwide crude prices), pipeline prorationing is a more probable risk. In this connection, it is important to note that plausible alternatives to our models can be constructed. For example, we assume in our market constraint case that both throughput on TAPS and Prudhoe Bay production are restricted to 1.5 million B/D by market limitations. Alternatively, one may posit that new discoveries on the North Slope (from NPR #4, for example) would constrain production from Prudhoe Bay but afford maximum rates of pipeline utilization. In that case, the per-barrel tariff for TAPS would be lower. Nevertheless, maximum utilization of TAPS would result in higher integrated margins and larger total earnings on TAPS (owing to higher throughput).

A Comment on Proved Oil Reserves

In recent months questions have been raised about the exact size of proven crude reserves in the main field at Prudhoe Bay. When all aspects of the controversy are considered, the prominent 9.5 billion barrel estimate originally made and subsequently reaffirmed by De Golyer & MacNaughton geologists remains fundamentally unchallenged.

De Golyer & MacNaughton estimate that the main field at Prudhoe Bay--including the huge Sadlerochit reservoir and the lesser Shublick and Sag River sandstone reservoirs--contains approximately 9.5 billion barrels of proved crude and condensate reserves. The total comprises 9.1 billion barrels of crude and 440 million barrels of condensate (a gaseous hydrocarbon in the reservoir, which liquefies upon production at the wellhead). The underlying reserves in place are estimated at 23.8 billion barrels; the projected recovery factor is 40%.

A recent study by H. K. Van Poollen and Associates, commissioned by the Oil and Gas Division of Alaska's Department of Natural Resources, estimated crude in place at 19.1 billion barrels. The study simulated Sadlerochit reservoir behavior (on a computer) under conditions of varying rates of crude production, water injection into the reservoir, and natural gas production. Maximum oil recovery was estimated at 8.2 billion barrels when it was assumed that most of the gas was reinjected; the optimum producing rate was 1.2 million B/D. Alternatively, 7.9 billion barrels were deemed recoverable under conditions of only partial reinjection of the gas (with sales limited to 2 billion cubic feet a day) and limited waterflood; in this case, the oil producing rate could rise to a peak 1.6 million B/D. The study pointed out that careful reservoir management could likely prevent loss of ultimately recoverable oil reserves even if the bulk of the gas were produced.

The Van Poollen study caused some consternation. Atlantic Richfield, however, has since clarified the issue, noting that the Van Poollen estimate excluded crude reserves in the smaller reservoirs and condensate as well, and concluded that the results of the study were not at significant variance from the De Golyer & MacNaughton estimate of recoverable oil reserves.

It is important to recall that all pre-operational estimates of proved reserves from a new field are necessarily subject to revision over time. Reserves are routinely re-estimated for oil fields over their productive lives as subsequent development and operations extend knowledge of the reservoir. The early estimation of oil reserves in the main field at Prudhoe Bay has proved quite reliable upon extensive development, probably because of the concentration and uniformity of pay sands. In contrast, initial estimates of reserves in highly-fractionated, complex reservoirs, like those of the Kuparuk area, can undergo radical reevaluation as experience is gained. Annual reporting of new discoveries is often made before extensive drilling and subsequent measurement have taken place; subsequent re-estimation often results in changes which later appear as revisions to initially-estimated discoveries. As a final comment, we would add that De Golyer & MacNaughton are noted for their conservative estimation of reserves. In the following section, we observe that the major revisions of Prudhoe Bay reserves have been in regard to the companies' equities in these reserves.

TAPS Tariffs

The tariffs for TAPS in our earnings models are based on company estimates of capital costs that predate the recent revision to $7 billion for capacity of 1.2 million B/D. Our tariffs reflect capital cost of $6.8 billion for initial capacity, $1.1 billion for capitalized interest on pipeline debt during the construction period, $500 million for expansion to 1.5 million B/D, and $350 million for expansion to maximum capacity of 2.0 million B/D. The latest increase in the estimated capital cost of TAPS, plus the higher profit (and related taxes) allowed on the enlarged investment base, would raise the 1981 tariff in our "reserves constraint" case from $4.15 to $4.35 a barrel. As explained below, both tariffs reflect a somewhat lower rate of return than the maximum permitted by the Interstate Commerce Commission (I.C.C.). The suggested increase in the TAPS tariff would have the effect of lowering the wellhead price by a comparable amount--from $6.35 to $6.15 a barrel if we assume a market price for crude on the West Coast of $11.00 a barrel.* Obviously, per-barrel cost of the integrated project would rise, and profitability would shift in favor of TAPS at the expense of earnings in the field. Interestingly, owing to this shift in the locus of earnings, per-barrel earnings on the integrated project (pipeline and field combined) would change only marginally, because of the higher incidence of taxation at the wellhead compared with TAPS. In effect, the penalty of incurring higher capital costs on TAPS would be assessed against the tax collectors rather than the companies (more below). In view of this outcome, and of the uncertainty enveloping other assumptions which underlie our tariff calculations --interest rates on debt, assumed rate of return, and Alaskan taxes--the recent increase in the estimated cost of TAPS alone hardly warrants tariff recalculation at this time, and might even suggest a specious accuracy.

The TAPS tariffs incorporated in our earnings models assume a 25-year economic life for the system. Depreciation of invested capital is arbitrarily calculated on a unit-of-throughput basis for both tax and financial accounting. The tariffs do not reflect the substantial investment tax credits that will accrue to the parents of owner-affiliates of TAPS from their investments in the pipeline. The tariffs include operating costs of $0.20 per barrel. Interest expense on TAPS debt is assumed at 9.3% per annum. Alaska's property tax is computed at 2% per annum on average invested capital (excluding interest during construction), assuming straight-line depreciation. State income tax is computed at 9.4% and federal income tax at a normalized 48%.

TAPS represents a distinct, and very important, profit (as well as cost) center in the integrated economics of North Slope oil. The locus of per-barrel profits on the North Slope is of particular interest to the companies because their current equities in TAPS may still differ somewhat from their eventual equities in production. (The July, 1974 revision of TAPS equities narrowed previous very marked discrepancies.) Such variances, however, would depend critically on the production potential of the Prudhoe Bay reservoirs, assumed rates of reservoir production, and determination of definitive equities in the three reservoirs. To the extent that eventual equities in TAPS do conform closely to equities in production, North Slope companies will have a clear preference for the highest permissible tariff and the lowest possible wellhead. This preference reflects the higher incidence of total taxation on the wellhead than on TAPS, even under current tax regimes. The elimination of statutory depletion reinforced this preference. So, too, would any higher effective rate of taxation by Alaska on production earnings.

Obviously, Alaska will have an equally keen interest in the division of earnings between TAPS and the wellhead, hence in the pipeline tariffs to be posted by the companies. Alaska will surely press for the lowest tariffs possible and the commensurately highest wellhead price, since the wellhead is the base for computing the value

* Market price - tanker transportation - TAPS tariff = wellhead; $11.00 - $0.50 - $4.35 = $6.15.

of its royalty oil, and for computing severance tax too. An "excess profits" tax of the type now under consideration in Alaska would sever part of Alaska's taxes on oil from reference to the wellhead price, since "excess value" would by-pass the effect of pipeline tariff on production value. As noted in the chapter on tax issues, "excess value" would be determined on the West Coast--i.e. before consideration of pipeline tariff. (The tax calculation would not wholly ignore imputable production value; such value would still govern liability for severance tax.) Nevertheless, the thrust of Alaskan taxation is toward maximizing the state's near-term income from oil. Thus, Alaska will probably persist in its efforts to minimize the tariff on TAPS. Alternatively, Alaska could resume its previous although (abortive) efforts to raise taxes on earnings arising from TAPS.

The I.C.C. permits owners of interstate pipelines to receive an 8% annual return on their net "replacement" costs, with distribution of dividends limited to the equivalent of a 7% rate of return. In our "reserves constraint" model, an I.C.C. return of 7% translates into an 15% annual return on our calculation of book investment over the life of the project (see table on page IV - 9). The associated annual return on the 15% equity portion of capital averages out to 127%. We have assumed, however, that the pipeline tariffs ultimately posted by the companies will represent negotiated levels--i.e., lower than the maximum permitted by the I.C.C., but high enough to cover all costs plus a "fair" return on total capital employed.

Formalistic computation of TAPS tariffs results in significant year-to-year changes in the tariff within each model. Realistically, the companies are likely to "smooth" or average out tariffs over a period of years. The process of smoothing tariffs in such a manner as to maintain at least minimum profitability while avoiding excessive (by I.C.C. standards) profits in any year inevitably leads to tariff profiles which yield rates of return below the maximum permitted by the I.C.C. Our earnings models incorporate the assumption of smoothed tariffs.

Pipeline Economics

The economics of North Slope oil vary considerably with assumed utilization of TAPS. High levels of throughput in the pipeline make for high integrated earnings per barrel.

Maximum capacity of TAPS is estimated at 2 million B/D. In our models, throughput over the 25-year economic life of the system ranges from approximately 3.5 billion barrels in the "reserve constraint" to 13.5 billion barrels in our "production potential" case and 13 billion barrels in the "market constraint" model. In our "reserves constraint" model, TAPS throughput never exceeds 1.5 million B/D and declines to 1 million B/D by 1990. In contrast, in our "production potential" model, throughput reaches 2 million B/D by 1984 and remains at a high level through the 1990's. In our "market constraint" model, throughput again never rises above 1.5 million B/D but is sustainable at that level through the 1990's, since the underlying reserves are assumed to be 13.5 billion barrels as in our "production potential" case. (Note, however that cumulative throughput on TAPS over 25 years amounts to 13 billion barrels.)

TAPS TARIFFS

(Dollars per Barrel)

	Unsmoothed Tariff[a]	Smoothed Tariff[b]
	"Reserves Constraint" Model	
1978	$5.48	$4.60
1981	4.54	4.15
1986	4.19	4.15
Average Tariff Over Project Life	4.93	4.23
	"Production Potential" Model	
1978	$5.18	$4.30
1981	3.96	3.40
1986	3.25	3.00
Average Tariff Over Project Life	3.81	3.50
	"Market Constraint" Model	
1978	$5.05	$4.85
1981	4.29	4.00
1986	3.92	3.30
Average Tariff Over Project Life	3.81	3.54

a. Tariff based on the I.C.C.'s maximum 7% return on replacement cost.

b. Tariff kept constant over extended periods, permitting at least minimum profits in every year but precluding a return above the I.C.C. maximum in any year.

Economies associated with high levels of throughput reflect marked disparities between various increments to capacity and related capital costs. Whereas the capital cost of TAPS capacity on the first 1,200 TB/D is $7.9 billion, the incremental cost on the next 800 TB/D of capacity may be only $850 million. The disparity in incremental capital cost tends to lower unit depreciation, particularly in the high volume ("production potential") model relative to non-cash charges in the other two models. However, lower unit depreciation in the "production potential" model is not mirrored in higher earnings per barrel on TAPS (as is normally the case when revenue is a datum). Quite the contrary! Earnings, like depreciation, are a separately calculated component entering the buildup of the tariff. Earnings are calculated as a percentage return on invested capital (partially adjusted upward for inflation). Capital (and returns) varies only moderately among models. Per barrel results vary greatly,

TAPS EARNINGS AND RATES OF RETURN*

(Dollars per Barrel)

	"Reserves Constraint"	"Production Potential"	"Market Constraint"
Annual Earnings per Barrel under Smoothed Tariffs:			
1978	$0.83	$0.83	$1.09
1981	0.86	0.67	0.87
1986	1.03	0.68	0.69
Average Earnings over Project Life:			
Under Smoothed Tariffs	$1.04	$0.91	$0.90
Under Unsmoothed Tariffs	1.37	1.06	1.03
	Rates of Return on TAPS		
Under Smoothed Tariffs			
Earnings/I.C.C. Valuation	5.3%	6.0%	6.1%
Earnings/Total Capital Employed	11.5	12.9	11.3
Earnings/Equity Capital	96.8	89.0	75.4
Under Unsmoothed Tariffs:			
Earnings/I.C.C. Valuation	7.0%	7.0%	7.0%
Earnings/Total Capital Employed	15.1	15.0	12.9
Earnings/Equity Capital	127.4	103.4	86.0

* See table of contents of Appendix Tables for reference to detailed calculation of earnings on TAPS.

however, owing to the more significant variations in throughput volumes. Thus, earnings per barrel tend to be lower in the highest-volume model than in the lower-volume models (particularly the "reserves constraint" case) and for essentially the same reason that depreciation is lowest in the highest volume case--the relatively greater disparity in throughput than in capital requirements. So, too, the tariff on TAPS is invariably lowest in our highest--throughput ("production potential") model, and contrastingly highest in our lowest-throughput ("reserves constraint") model. The economies implicit in high throughputs are very real, nevertheless, but are reflected in higher wellhead prices (and earnings) rather than on TAPS *per se*, where the economics arise. The process of smoothing tariffs distorts comparisons among tariffs in particular years, but only to a moderate degree.

TAPS Earnings per Barrel

The preceding table presents earnings per barrel on TAPS for our three earnings models in selected years (1978, 1981 and 1986). The annual earnings per barrel are calculated under smoothed tariffs and reflect returns on the I.C.C. valuation base which range from 5.3% in our "reserves constraint" model to 6.1% in our "market constraint" model (shown in a lower panel of the table). Corresponding results are shown per barrel of throughput over project life. In addition to rates of return for each model based on the modified I.C.C. investment base, the table also presents, under smoothed tariffs, returns on total capital actually employed in TAPS as well as returns on equity capital invested. For comparison with earnings per barrel and rates of return under smoothed tariffs, the table also includes corresponding results under unsmoothed tariffs--i.e. when rates of return are calculated at the maximum 7% permitted by the I.C.C.

Wellhead Prices

The wellhead prices on which our models of production earnings are based are derived from assumed crude values in southern California of $11.00 and $13.00 per barrel less transportation charges (tanker costs and TAPS' tariff).* The price of a Prudhoe-type crude (taken as Signal Hill 27° API gravity) might approximate $11.00 per barrel by the close of 1976. If we allow for a generous increase in the average price of domestic crude in 1977 within the constraints of the Energy Conservation and Policy Act and if we also assume that the bulk of the increment accrues to upper-tier crude, then the price of a Prudhoe-type crude in California would be roughly $13.00 per barrel by early 1979, the first full-year of North Slope production.

Derivation of alternative wellhead prices in each of our models is shown in the table following. A market value for domestic crude of $11.00 a barrel nets back to the wellhead a range of $5.65 to $6.20 a barrel. The range of wellhead prices, given a market value of $13.00, is $7.65-$8.20 a barrel. Note that wellhead value in each instance is moderately below the expected <u>average</u> price of domestic crude of $8.43 a barrel in 1977, and far below any conceivable level of upper-tier crude prices. (Our working assumption is that whoever is President in 1977 will not move to bar any increase in crude prices at all. We assume similar rationality for the new Congress.)

As in the case of TAPS, our earnings models for crude production assume a 25-year economic life of reserves. It should be noted, however, that in the "market constraint" model the life of production would be longer, owing to the assumed restriction on output. Depreciation of invested capital is calculated on a unit-of-production basis for both tax and financial accounting. We assume that development capital is entirely equity capital--by now a tenuous assumption. Federal income taxes are normalized. Operating costs are estimated at $0.25 per barrel. Assumptions regarding Alaskan taxes are discussed below.

* Appendix tables also present the impact on production earnings of a pessimistic $9.00-a-barrel price for crude on the West Coast.

REPRESENTATIVE DERIVATION OF WELLHEAD PRICES AT PRUDHOE BAY, 1978

(Dollars per Barrel)

		"Reserves Constraint"	"Production Potential"	"Market Constraint"
		$11.00 Per Barrel Crude Price		
(1)	California Price	$11.00	$11.00	$11.00
(2)	Tanker Cost (Valdez-L.A.)	0.50	0.50	0.50
(3)	(1-2) Price at Valdez	10.50	10.50	10.50
(4)	TAPS Tariff	4.60	4.30	4.85
(5)	(3-4) Wellhead Price	$ 5.90	$ 6.20	$ 5.65
		$13.00 Per Barrel Crude Price		
(1)	California Price	$13.00	$13.00	$13.00
(2)	Tanker Cost (Valdez-L.A.)	0.50	0.50	0.50
(3)	(1-2) Price at Valdez	12.50	12.50	12.50
(4)	TAPS Tariff	4.60	4.30	4.85
(5)	(3-4) Wellhead Price	$ 7.90	$ 8.20	$ 7.65

Production Earnings Per Barrel

Current Tax Regimes, Alternative Crude Prices

Given the interplay between TAPS tariffs and wellhead prices, per-barrel earnings on production are highest in the "production potential" model, where the tariff and unit earnings on TAPS are lowest. Production earnings in our "production potential" model for 1978--under a market value for crude of $11.00 per barrel--approximate $2.34 per barrel, compared with $2.17 per barrel in our "reserves constraint" model and $2.07 per barrel in our "market constraint" model. An increase in the market value of crude from $11.00 to $13.00 per barrel would raise production earnings in each model by $0.87 per barrel (see table on following page).

Over time, wellhead prices increase substantially--given constant market values for crude--owing to the declines in TAPS tariffs in each model. After-tax profits on production advance at a slower rate owing to significant increases in per-barrel capital costs. As noted earlier, sizeable additions to capital investment are assumed to occur in each model over most of project life to recover proved reserves. The very large investment in tertiary recovery--assumed to yield 2 billion barrels of reserves but only a modest (100 TB/D) increment to production--is powerfully reflected in unit capital cost by 1985 in the "production potential" model.

DETAILED CALCULATION OF PROJECTED PRODUCTION EARNINGS
CURRENT TAX REGIMES,
1985 VERSUS 1978

(Dollars per Barrel)

	"Reserves Constraint" Case	"Production Potential" Case	"Market Constraint" Case
Year 1978			
$11.00 Per Barrel Crude Price			
Wellhead Price	$5.90	$6.20	$5.65
Oper./Cap. Cost	0.67	0.59	0.65
Property Tax	0.16	0.16	0.16
Severance Tax	0.46	0.48	0.44
State Income Tax	0.43	0.47	0.41
Federal Income Tax	2.01	2.16	1.92
Production Earnings	$2.17	$2.34	$2.07
$13.00 Per Barrel Crude Price			
Wellhead Price	$7.90	$8.20	$7.65
Oper./Cap. Cost	0.67	0.59	0.65
Property Tax	0.16	0.16	0.16
Severance Tax	0.61	0.64	0.59
State Income Tax	0.61	0.64	0.59
Federal Income Tax	2.81	2.96	2.72
Production Earnings	$3.04	$3.21	$2.94
Year 1985			
$11.00 Per Barrel Crude Price			
Wellhead Price	$6.35	$7.10	$6.50
Oper./Cap. Cost	0.91	1.07	0.82
Property Tax	0.17	0.23	0.21
Severance Tax	0.49	0.55	0.51
State Income Tax	0.45	0.49	0.47
Federal Income Tax	2.08	2.28	2.16
Production Earnings	$2.25	$2.48	$2.33
$13.00 Per Barrel Crude Price			
Wellhead Price	$8.35	$9.10	$8.50
Oper./Cap. Cost	0.91	1.07	0.82
Property Tax	0.17	0.23	0.21
Severance Tax	0.65	0.71	0.66
State Income Tax	0.62	0.67	0.64
Federal Income Tax	2.88	3.08	2.96
Production Earnings	$3.12	$3.34	$3.21

Alaskan Tax-Proposals

We have calculated wellhead earnings on Prudhoe Bay crude in each of our three basic models--and for the alternative crude prices discussed above--employing the following assumptions about Alaskan taxation of oil production earnings. We initially compute production earnings under Alaska's current tax regime. We then apply, as best possible, the proposed changes in Alaska's tax laws that follow upon the proposals of the Interim Committee on Taxation and Revenue (the "Huber proposals"). Our exercises allow for a varying measurement of the "excess value" subject to an excess value tax (EVT). We assume in each of the latter Alaskan-tax cases that the severance tax will rise from an average 7.8% of wellhead value to 12.6% and that the state income tax (renamed a "net proceeds" tax) of 9.4% will continue to apply. To date, the proposal for an excess value tax remains somewhat ambiguous, as regards both the measurement of excess value and the rate of taxation. We have assumed that excess value is the difference between the sanctioned (or market-determined) price in California and a variable deemed value. The excess value tax rate is taken at a flat 40% after allowance for deduction of severance tax and net proceeds (state income) tax on the excess value and after allowance for a minimum $1.00-a-barrel margin before income taxes (illustrated below). As we noted earlier, one of the nagging questions remains whether or not the escalation in deemed value will move in line with market value of comparable crude on the West Coast (or in the Midwest). In our optimistic tax case, we allow for the deemed value to move up dollar-for-dollar with market value--i.e., excess value remains unchanged. In our second, pessimistic case, we hold the deemed value at a fixed level while market price increases--i.e., excess value subject to EVT rises in line with market value.

The Huber proposals on Alaskan oil taxes--so far as we can decipher them--require both some illustration and explanation. The following table extends our "reserves constraint" case to include the proposed taxation by Alaska of earnings on North Slope crude when realizations are divided into two values--the deemed long-term value and the excess value. The market value of crude in California is assumed to be $11.00 a barrel--the approximate price of upper-tier crude (by year-end 1976). The calculation is for a net company barrel (after deduction of royalty oil).

The first column presents the computation of production earnings and taxes under current parameters. Alaskan taxes consist of an average severance tax on wellhead price of 7.8%, property tax of 2%, and state income tax of 9.4%. The next three columns present production earnings and taxes under legislation proposed by the special Huber committee.

As noted earlier, these computations split the assumed $11.00-a-barrel market value into two components--the long-term (deemed) value and excess value. With respect to calculation of taxes and earnings on the long-term value, the only change from the current rules is the increase in severance tax--from an average 7.8% to 12.6%.

IMPACT OF PROPOSED CHANGES IN ALASKAN OIL TAXATION
ON COMPANY PRODUCTION EARNINGS
"RESERVES CONSTRAINT" MODEL, 1978
$11.00 PER BARREL MARKET CRUDE VALUE

(Dollars Per Barrel)

		Proposed		
	Current	Long-Term Value	Excess Value	Combined
(1) California Price	$11.00	$7.00	$4.00	$11.00
(2) Tanker Cost	0.50	0.50	....	0.50
(3) (1-2) Price at Valdez	10.50	6.50	....	10.50
(4) TAPS Tariff	4.60	4.60	....	4.60
(5) (3-4) Wellhead	$ 5.90	$1.90	....	$ 5.90
Severance Tax (7.8%)	-0.46	(12.6%) -0.24	-0.50	-0.74
O/C Costs, Prop. Tax	-0.83	-0.83	....	-0.83
Pre-Tax Income	$ 4.61	$0.83	$3.50	$ 4.33
State Income Tax (9.4%)	-0.43	0.08	0.33	0.41
Income after S.I.T.	$ 4.18	$0.75	$3.17	$ 3.92
(Excess Value Adj.)			(-0.67)	
Income after SIT & EVA			2.50	
Excess Value Tax (41%)			-1.03	-1.03
Income before FIT	$ 4.18	$0.75	$2.14	$ 2.89
FIT	2.01	0.36	1.03	1.39
Production Earnings	$ 2.17	$0.39	$1.11	$ 1.50

The excess value component of total market value represents the difference between federally sanctioned (or OPEC-determined) market value f.o.b. West Coast markets and the long-term (deemed) value, subject to adjustment (described below). Values are compared at the same F.O.B. location. In our illustration, we start with the current rolled-back price of crude in California and subtract long-term value ($11.00 - $7.00 = $4.00/barrel). This conforms to examples accompanying the legislation submitted in Alaska. The long-term value of $7.00 a barrel is contained in the draft legislation of the Huber committee. It represents a suggested value for a current estimate in explanatory material, but would escalate with the wholesale price index* from the date when the legislation went into effect.

Severance tax is deductible from the unadjusted excess value (EV) before application of the excess profits tax (EVT)--\$4.00 X .126 = \$0.50. Excess value would apparently be subject to the new net proceeds tax--formerly the state income tax, at the same rate--\$3.50 X .094 = \$0.33. The final adjustment to excess value before exaction of the EVT relates to a minimum margin for the companies. The producing company would be allowed minimum "net proceeds" of \$1.00 per barrel (pre-tax income in our table) from the long-term value in addition to income remaining after net proceeds tax, EVT and federal income tax). In computing net proceeds of the company, the severance tax actually paid (on the full market value of \$11.00 a barrel) and operating/capital costs are deducted from long-term value netted back to the wellhead (\$1.90 - \$0.74 - \$0.83 = \$0.33). If net proceeds work out to less than \$1.00 a barrel--as in our illustration--then the excess value is further reduced by the amount of the shortfall, or by \$0.67 a barrel in our table. In all then, initially excess value is subject to three adjustments--for severance tax and net proceeds tax (which accrue to Alaska, of course) and for any shortfall in net proceeds to the company. EVT in our example is \$1.03 a barrel [(\$4.00 - \$0.50 - \$0.33 - \$0.67) X .41 - \$1.03]. Total tax liability to Alaska comprises 46.5% of unadjusted excess value of \$4.00 a barrel.

Under an \$11.00 a-barrel assumption for crude value on the West Coast, estimated earnings on main field production would be shaved from \$2.17 to \$1.50 per barrel if the proposed tax changes are adopted. (Allowing for inclusion of earnings on TAPS, the integrated margin would shrink from \$3.00 to \$2.33 per barrel.) Concomitantly, Alaska's share of net operating income on production** would soar from 20% to 45%. The companies' share would contract from 41% to 29%, and federal take from 38% to 26%.

The following table illustrates in some detail the impact of proposed changes in Alaskan taxation on production earnings and integrated margins when we assume \$13.00 per barrel as the prescribed market value for Prudhoe-type crude. The underlying model, which shapes the configuration of unit costs, is our "reserves constraint" case, allowing for the substantial increase in market price permitted under federal law by late 1977, or early 1978. For purposes of measuring excess value subject to a 41% tax rate,

* Indexing of crude values has become a favorite method for determining "just prices" at the federal and now state level of government, but unacceptable from OPEC. It is interesting to note that under existing tax legislation in Alaska, the minimum (per-barrel) severance tax is tied to the wholesale oil price index, but this adjustment is rejected when it might affect company revenues on which excess value taxes are computed because of the surge in that index attributable to the rising cost of oil imports.

**Total Alaskan taxes (severance, property, net proceeds and EVT) ÷ wellhead less operating and capital costs.

IMPACT OF PROPOSED CHANGES IN ALASKAN OIL TAXATION
ON COMPANY PRODUCTION EARNINGS
"RESERVES CONSTRAINT" MODEL, 1978

$13.00 PER BARREL MARKET CRUDE VALUE

(Dollars Per Barrel)

	Current Tax Regime		"Optimistic"[a]	"Pessimistic"[b]
(1) California Price	$13.00		$13.00	$13.00
(2) Tanker Cost	- 0.50		- 0.50	- 0.50
(3) (1-2) Price at Valdez	$12.50		$12.50	$12.50
(4) TAPS Tariff	- 4.60		- 4.60	- 4.60
(5) (3-4) Wellhead	$ 7.90		$ 7.90	$ 7.90
Severance Tax (7.8%)	- 0.61	(12.6%)	- 1.00	- 1.00
Oper./Cap. Costs[c]	- 0.83		- 0.83	- 0.83
Pre-Tax Income	$ 6.46		$ 6.07	$ 6.07
State Income Tax (9.4%)	- 0.61		- 0.57	- 0.57
Income after S.I.T.	$ 5.85		$ 5.50	$ 5.50
Excess Value Tax (41%)	....		- 1.30	- 1.57
Income before FIT	$ 5.85		$ 4.20	$ 3.93
Federal Income Taxes	- 2.81		- 2.02	- 1.89
Production Earnings	$ 3.04		$ 2.18	$ 2.04

a. Long-term crude value for computing excess value, $9.00 per barrel in the market or $3.90 per barrel at the wellhead.
b. Long-term crude value for computing excess value, $7.00 per barrel in the market or $1.90 per barrel at the wellhead.
c. Includes property tax.

a critical question will be the rate at which base price (long-term value) will be permitted to escalate relative to the prescribed market escalation for new crude.

In the following exercise, we posit alternative assumptions about the level of long-term values associated with an increase in market value for crude from $11.00 to $13.00 per barrel. The first, or "optimistic," variation permits an initial $7.00-per-barrel deemed value to rise to $9.00 per barrel by 1978, the first full year of Prudhoe Bay production; this assumption leaves excess value unchanged at $4.00 per barrel as market price increases.* The second, or "pessimistic", variation in long-term value holds the latter constant at $7.00 per barrel as market price rises to $13.00 per barrel, thus permitting excess value to widen to $6.00 per barrel.

Under an assumption of $13.00-a-barrel for crude value on the West Coast and an "optimistic" assumption as to escalation of long-term value for crude, estimated earnings on main field production in 1978 would be shaved from $3.04 to $2.18** per barrel on account of higher severance tax and imposition of the excess value tax. (The integrated margin would shrink from $3.87 to $3.01 per barrel.)

In our "pessimistic" case, the estimated margin on production would sink from $3.04 to $2.04 per barrel, and the integrated margin from $3.87 to $2.87 per barrel.

Investors will be interested in the sensitivity of production earnings per barrel to a $1.00-a-barrel change in the prescribed market value of crude.*** Such measurement (as noted) necessitates a concomitant assumption as to corresponding policy changes regarding long-term values--as we have done above for assumed change in market value.

The following table presents the estimated sensitivity of per-barrel profit margins in each of our three basic models to a $1.00 per-barrel change in market value. For declines in market value below $11.00 per barrel, we assume, alternatively, that (1) long-term crude values decline commensurately, leaving excess value unchanged, and (2) long-term values remain constant while excess value shrinks.

---

* The draft legislation submitted by the Huber committee on the excess value tax specifies that long-term price "means any price for a barrel of oil or its energy equivalent of more than $7.00 per barrel or the amount determined by the department. In no event, may the amount determined by the department exceed $7.00 per barrel plus the increase in the national wholesale price index since the tax went into effect." The explanatory material accompanying the draft legislation hypothesized a more generous 1974 base price of $7.00 per barrel from which to escalate long-term value. If this allowance for inflation were permitted, long-term value could reach $9.00 per barrel by 1978.

** Incidentally, the per-barrel margins in this example of the $13.00-a-barrel market price under the proposed Alaskan tax regime are comparable to results in the $11.00-a-barrel case under the current tax regime.

*** The sensitivity of companies' per share earnings to a $1.00-a-barrel change in market value for crude is discussed and illustrated in the next chapter.

SENSITIVITY OF PRODUCTION EARNINGS PER $1.00/BARREL
CHANGE IN MARKET VALUE OF CRUDE

(Dollars Per Barrel)

	Alaskan Tax Regimes	
	Proposed	Existing
Margins on Production, $11.00/bbl. Crude Price, 1978		
"Reserves Constraint" Model	$1.51	$2.17
"Production Potential" Model	$1.57	$2.34
"Market Constraint" Model	$1.46	$2.07
Earnings Impact of $1.00/bbl. Change in Market Crude Value		
Assuming:		
$1.00/bbl. Decline in Market Value		
Excess Value Declines $1.00	-$0.24	-$0.43
Excess Value Constant	-$0.23	
$1.00/bbl. Increase in Market Value from $11.00 to $12.00/bbl.		
Optimistic: Excess Value Constant	+$0.23	+$0.43
Pessimistic: Excess Value Increases $1.00	+$0.24	
$1.00/bbl. Increase in Market Value above $12.00/bbl.		
Optimistic: Excess Value Constant	+$0.41	+$0.43
Pessimistic: Excess Value Increases $1.00	+$0.24	

For increases in market value we present similar "optimistic" and "pessimistic" constructions for determining long-term value.

Under existing petroleum taxation in Alaska, production margins vary by $0.43 per barrel for each $1.00 change in market value for crude. It is interesting to note that when market value is assumed to decline by $1.00 a barrel under the proposed tax regime in Alaska, the corresponding decline in per-barrel earnings on production is limited to $0.23-$0.24 per barrel regardless of whether excess value changes. In fact, the EVT declines when price declines although excess value is held constant. The tax reduction follows from an incremental deduction from excess value (for the worsened shortfall in net proceeds attending the assumed decline in long-term value) before applying the 41% tax. The increase in shortfall of net proceeds reduces excess value (held constant otherwise) and EVT by approximately the same amount as a decline in excess value (and EVT) attributable to holding long-term value constant when market value declines. The comparable phenomenon is apparent when we examine the impact on earnings per barrel of an increase in market value from $11.00 to $12.00 a barrel.

NORTH SLOPE EARNINGS PER BARREL IN
"RESERVES CONSTRAINT" MODEL

	July-Dec. 1977	1978	1980	1985
$9.00 Crude Price	Current Tax Regime			
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	1.27	1.31	1.29	1.39
Total	$1.33	$2.14	$2.32	$2.41
$11.00 Crude Price				
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	2.13	2.17	2.15	2.25
Total	$2.19	$3.00	$3.18	$3.27
$13.00 Crude Price				
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	3.00	3.04	3.06	3.12
Total	$3.06	$3.87	$4.09	$4.14
$9.00 Crude Price	Proposed Tax Regime			
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	1.00	1.03	1.02	1.07
Total	$1.06	$1.86	$2.05	$2.09
$11.00 Crude Price				
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	1.48	1.51	1.50	1.55
Total	$1.54	$2.34	$2.53	$2.57
$13.00 Crude Price[a]				
TAPS	$0.06	$0.83	$1.03	$1.02
Sadlerochit	2.14	2.18	2.16	2.26
Total	$2.20	$3.01	$3.19	$3.28

a. Assumes "optimistic" case for determination of "excess value" subject to proposed 41% tax in Alaska.

Once market value reaches $12.00 a barrel, however, net proceeds exceed $1.00 a barrel. Thus, when market value rises by $1.00 a barrel and excess value is held constant (i.e., long-term value increases commensurately with market value), earnings per barrel on production rise by $0.41 per barrel. No change occurs in excess value or EVT. In effect, incremental earnings equate with those under existing tax law in Alaska. (Of course, earnings on the full $13.00 value netted back to the wellhead will be smaller than under current tax legislation in Alaska.) However, were excess value to increase dollar-for-dollar with market price (i.e., long-term value remains unchanged), then incremental earnings on production from a $1.00 increase in crude value above $12.00 per barrel are again limited to $0.24 per barrel. (All these calculations are predicated upon the overall plausibility of critical case parameters in the earnings models.)

The "integrated earnings" shown on page IV - 19 approximate combined earnings per barrel on TAPS and main reservoir production for the companies as a group. Prospective earnings per barrel on Kuparuk/Lisburne production work out lower than margins on Sadlerochit crude owing to assumed higher capital costs. Under current tax regimes, Kuparuk/Lisburne results average out at approximately $0.40/bbl. below Sadlerochit margins; under the proposed tax regime, Kuparuk/Lisburne margins might be $0.20/bbl. lower. A market price for crude on the West Coast of $6.50-$7.00 a barrel would be required to ensure "adequate" profits on TAPS and to cover average total costs at the wellhead for Sadlerochit (main reservoir) crude. Production of Kuparuk/Lisburne reserves would probably require a minimum price for Prudhoe Bay crude of $7.50 a barrel.

Our models of industry earnings per barrel on North Slope crude encompass a requisite wide range of assumptions regarding throughput on TAPS, field production, prices and taxes. One may also posit alternative assumptions concerning Alaskan taxes, or interpolate cases within our range of assumptions. The table detailing the sensitivity of production earnings to a $1.00-a-barrel change in market value facilitates the use of alternative assumptions about market price.

Discounted-Cash-Flow Rates of Return

In this section we present DCF rates of return for our "reserves constraint" model under the alternative crude price and tax assumptions previously discussed. We have computed DCF returns for TAPS and production both separately and combined, using 1977 as the base year. Comparable calculations for our "production potential" and "market constraint" models are precluded by the conjectural basis of investment requirements and cash flows for tertiary recovery in the main (Sadlerochit) reservoir and the Kuparuk/Lisburne reservoirs.

The stream of investments in TAPS--including all participants--is based on the major companies' past and projected expenditures for capacity of 1,500 TB/D. We have reduced expenditures from 1972 through 1977 to take into account a fraction of the investment tax credits earned in the pre-production period. (The bulk of ITC accruing in this period will be taken after production begins; see below.) Cash flow from TAPS reflects the earnings derived in our "reserves constraint" model