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THE DETERMINATION OF EQUITABLE PRICING LEVELS  
FOR NORTH SLOPE ALASKAN CRUDE OIL

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Three field development plans were analyzed.

Case I: Only Prudhoe Oil Pool (consisting of Sadlerochit, Sag River and Shublik formations) is developed. Field is put on production in mid-1977. Production rate reaches 1.5 MMB/D by early 1979 and is held at that rate until mid-1986, and then declines. Gas sales begin in 1983 at 2 BCF/D.

TAPS' capacity expands to 1.5 MMB/D.

Case II: Field development plans include lower reserve estimates of Kuparuk and Lisburne Oil Pools. TAPS' capacity expands to next level of 2 MMB/D.

Prudhoe Oil Pool is produced at 1.6 MMB/D. Contributions of Kuparuk and Lisburne Oil Pools bring production rate to 1.77 MMB/D. Production rate peaks in 1986 and then declines.

Case III: Field development plans include upper reserve estimates of

Kuparuk and Lisburne Oil Pools. TAPS' capacity and Prudhoe Oil Pool production rate are unchanged from Case II.

Contribution of Kuparuk and Lisburne Oil Pools brings rate of production to 1.915 MMB/D. Production rate peaks in 1986 and then declines.

## Methodology and Results

1. Develop production rate forecast for each case.
2. Estimate investment in field and costs of operation for each development plan.
3. Estimate investment in TAPS and costs of TAPS' operation for 1.2, 1.5 and 2.0 MMB/D capacity.
4. Determine average transshipment costs from Valdez to West Coast ports. Cost of transshipment including terminal handling is 76 ¢/B.
5. Establish ceiling price (in 1976 dollars) at Valdez, based on price of comparable Saudi Arabian crude to West Coast refinery exclusive of entitlements.

	<u>\$/B</u>	
Price of Saudi Arabian crude FOB Ras Tanura	11.51	12.44
Transshipment to West Coast	1.33	
Import Fee	.21	
Terminal Handling	<u>.10</u>	
	13.15	
	<u>-.76</u>	
Ceiling price at Valdez	12.39	13.54

6. Compute tariff rate by year for each case. Average tariff rate for first 10 years of pipeline service:

Case I	4.50 \$/B
Case II	4.30 \$/B
Case III	4.20 \$/B

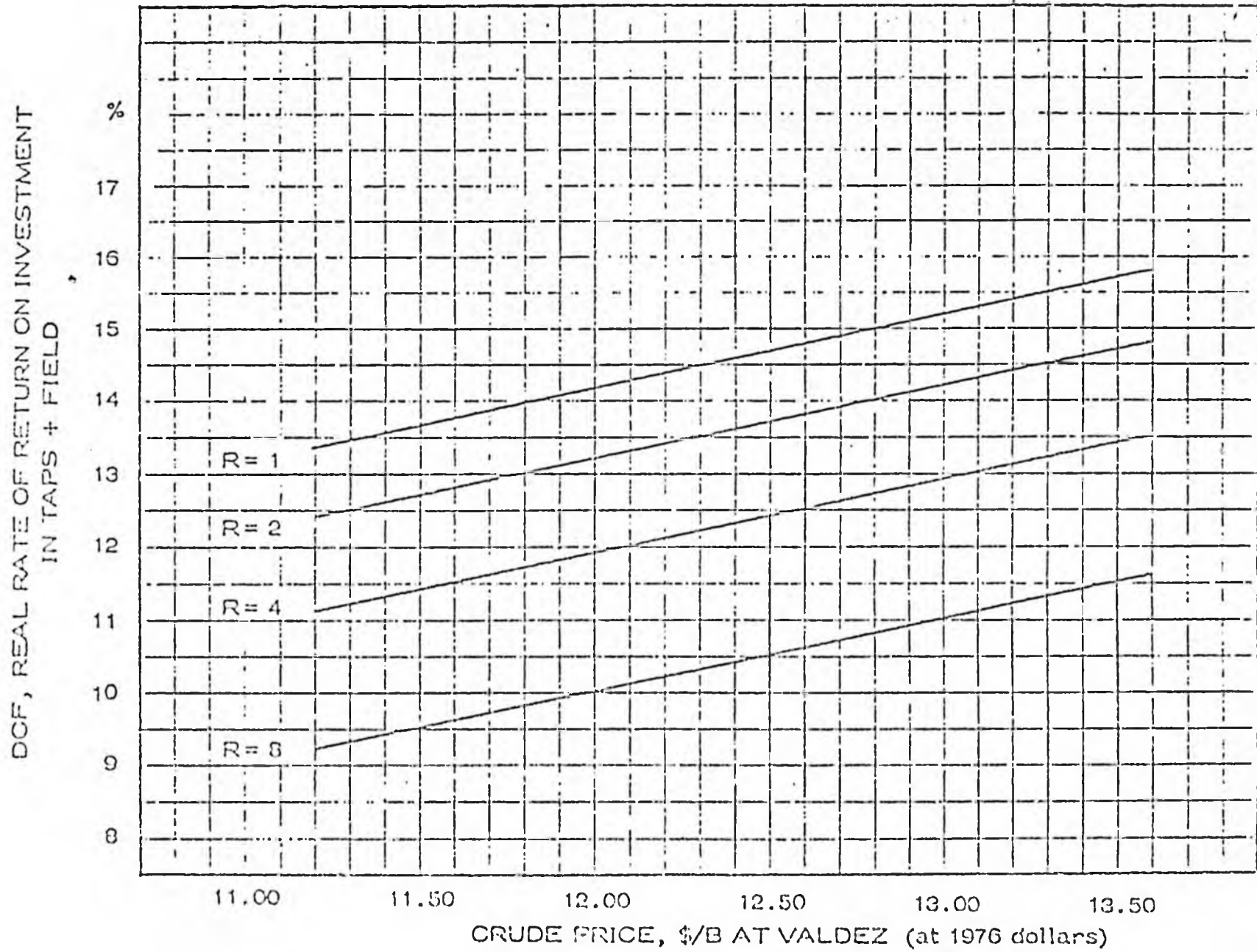
- Each TAPS owner has different experience with debt-to-equity ratio and interest rates. Each owner may set a different tariff.
  - ICC and Justice Department rulings set the ceiling on tariff rate. An owner can set tariff below ceiling, but Justice Department will not knowingly condone destructive competition. This still leaves a wide latitude for each owner to set a different tariff.
  - Owner may set the tariff rate annually (unsmoothed) or smooth the rate over several years.
7. Compute total operating costs of TAPS by year for each case to include:
- Cost of operations (in 1976 dollars)
  - Ad valorem taxes
  - State of Alaska corporate income tax
  - Federal corporate income tax
8. Compute ceiling well head price by year for each case. This is equal to ceiling price at Valdez minus tariff.

Use well head price to compute total field operating costs, including

- Cost of operations (in 1976 dollars)
- Ad valorem tax
- Royalty and payments to Alaska Native Fund
- Severance tax
- State of Alaska corporate income tax
- Federal corporate income tax

9. Compute annual gross revenue generated at Valdez at constant 1976 dollars plus revenue for gas sales in the field at 53 ¢/MCF (before conditioning to pipeline quality).
10. Adjust pre-1976 expenditures to 1976 dollars.  
  
By expressing pre-1976 investments and post-1976 investments and revenues in 1976 dollars, the uncertainty associated with forecasting the future rate of inflation is circumvented. The resulting rate of return is referred to as "real rate of return". Price levels thus determined need to be adjusted quarterly to reflect effects of inflation.
11. Compute DCF, after tax, real rate of return on total investment in TAPS and Prudhoe Bay Field using items 7, 8, 9 and 10 above.
12. Analyze sensitivity of rate of return to price at Valdez by changing it by one dollar increments. Repeat items 8 to 11 above.
13. Analyze sensitivity of rate of return to risk multiplier "R", where  $R = 1 + .5(S - 1)$ , and  $S =$  inverse of success ratio. Multiply total industry's expenditures on North Slope from 1959 until field discovery in 1968 by risk multiplier. The relationship between R and S assumes the unsuccessful exploratory ventures are expensed for federal income tax purposes.
14. Analyze sensitivity of rate of return to uncertainty in tariff determination
15. Analyze sensitivity of rate of return to variation in rate of throughput by comparing rates of return for Cases I, II, and III.

RELATIONSHIP BETWEEN  
RATES OF RETURN, RISK MULTIPLIER "R"  
AND CRUDE PRICES



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## Conclusions

- Rate of return is relatively insensitive to the rate of throughput. The increased cost of developing and operating the speculative and less productive reserves in the Lisburne and Kuparuk Oil Pools is substantially offset by the economy resulting from increasing TAPS' capacity from 1.5 to 2.0 MMB/D.
- The uncertainty in tariff determination has little effect on the rate of return. An increase in tariff shifts the tax obligation to TAPS from the field, and vice versa. Since the field taxable income is more heavily taxed, a lowering of tariff increases the total tax obligation but does not affect the rate of return significantly.
- A change of 1 \$/B in the price of crude at Valdez results in a net change in after tax revenue to the owners of 33 ¢/B. It also results in a 1% change in the rate of return.
- The risk multiplier has a dramatic effect on the rate of return. For Case I, with Valdez price of 12.40 \$/B:

<u>Risk Multiplier</u>	<u>Rate of Return %</u>
1	14.6
2	13.6
4	12.3
8	10.4

A risk multiplier of 3 to 4.5 (equivalent to success ratio of 1 in 7) is suggested. For this range of risk multiplier and an after tax, DCF, real rate of return of 12%, the price range at Valdez would be

. 11.50 to 12.40 \$/B.

Comparable well head price range would be:

Case I                      7.00 - 7.90

Case II                     7.20 - 8.10

Case III                    7.30 - 8.20

### Recommendations

- Equitable prices of Prudhoe Bay crude at Valdez fall between 11.50 and 12.40 \$/B (1976 dollars), to be adjusted quarterly for inflation.
- Pricing at Valdez provides a built-in incentive for developing the speculative Kuparuk and Lisburne Oil Pools.
- Pricing at Valdez circumvents the uncertainty in tariff rates.
- Equitable prices of Prudhoe Bay crude at the well head for Case I fall in the range of 7.00 to 7.90 \$/B (1976 dollars), to be adjusted quarterly for inflation.
- This study did not address itself to the implications on pricing of any surplus of crude on the West Coast.

## I. Relationship Between Prices at West Coast Ports, Valdez and Well Head

The major components of the total system required to bring the Prudhoe Bay crude to the West Coast refineries are:

1. The Prudhoe Bay Field System
2. The Trans Alaska Pipeline System
3. The Transshipment System which transports the crude from Valdez to West Coast ports.

The price of Prudhoe Bay crude on the West Coast is equal to the price at Valdez plus the cost of transshipment. Similarly, the price at Valdez equals the well head price plus the pipeline tariff.

### Cost of Transshipment

The cost of transshipment per barrel is equal to the sum of the operating costs per barrel plus the capital charges per barrel required for depreciating the cost of the tanker over its life after allowing a 10% rate of return on investment. The transshipment cost is very sensitive to tanker size and to the length of the voyage from Valdez to the West Coast port. A detailed analysis and presentation of the costs of transshipment as a function of tanker size and length of voyage is presented in Chapter III.

To arrive at a representative transshipment cost to be used for relating the price at Valdez to the price at the West Coast, an average tanker size of 115 MDWT (which is the average size of tanker in the Valdez to West Coast fleet) was used. Furthermore, the length of the voyage was averaged

out by arbitrarily assuming that one-third of the Valdez to West Coast crude oil trade goes to Puget Sound and two-thirds to Long Beach.\*

### Pipeline Tariff

The price of Prudhoe Bay crude at Valdez represents an important point of departure. The pipeline tariff for moving Prudhoe Bay crude from the field to Valdez is computed according to a set of rulings established by the ICC and the Justice Department. The tariff thus calculated represents a ceiling which cannot be exceeded by the owners. The form of ownership of the trans-Alaska pipeline is one of undivided joint interest and permits each owner to post a separate tariff. The owners will probably post different tariffs for several reasons.

1. The actual interest paid on borrowed capital is recognized by the ICC as a component in the tariff computation. Interest charges vary from owner to owner, depending on the interest rate on the pipeline debt, and debt to equity ratio.
2. The ownership in the pipeline is not the same as the ownership in the field reserves.

The Justice Dept. will not knowingly permit destructive competition through tariffs that fail to cover expenses. That still leaves considerable room for variation in the tariffs posted by the different pipeline owners.

For this reason, the price of crude at Valdez and a rate of return based on the combined investment in the field and pipeline system take on an added significance. The trans-Alaska pipeline tariff is computed for the average owner according to the rules and regulations prescribed by the ICC

\* This assumption is examined in greater detail on page III-12.

and the Justice Department. The computed tariff is used to arrive at well head price which is the basis for computing:

1. Severance tax
2. State royalty
3. Payments to Alaska Native Fund
4. State and federal corporate income taxes.

## II. Rates of Return

The rates of return computed in this study are discounted cash flow, after tax (both state and federal) real rates of return on total investment.

Therefore for TAPS, the rate of return computation takes into account the entire capital investment in the pipeline (i.e. not limited to owners' equity). Similarly, therefore, it does not recognize construction interest, which is included in the ICC valuation base for tariff determination.

Predicting the future rate of inflation over the life of the project is subject to a high degree of uncertainty. On the other hand, reasonably reliable predictions can be made of the field producing potential, rates of throughput and operating and investment costs in terms of 1976 dollars. Therefore it is more meaningful to project all future costs and revenues in terms of 1976 dollars and to express all pre-investments also in terms of 1976 dollars. The resulting cash flow yields a real rate of return as distinguished from a nominal rate of return when discounted to determine a zero present worth. The price of oil thus determined is expressed in 1976 dollars and should be adjusted periodically after the fact to reflect the effects of inflation. Table I-1 was used to express pre-1976 investments in 1976 dollars.

QUALITY AND CHARACTERISTICS OF  
PRUDHOE BAY ALASKAN CRUDE OILIntroduction

The Prudhoe Bay Field consists of three principal hydrocarbon accumulations. These are the Kuparuk, the Prudhoe and the Lisburne Oil Pools, in order of increasing depth. The Prudhoe Oil Pool is the principal hydrocarbon accumulation in the Prudhoe Bay Field. It ranges in depth from approximately 8,700 feet to 9,300 feet and contains the majority of known proven reserves in the field. The pool is made up of the Sag River, Shublik and Sadlerochit formations. The productive intervals in this pool vary in gross thickness from approximately 20 to 600 feet. The Sadlerochit formation contains most of the reserves in the Prudhoe Oil Pool.

Current development plans focus on the Prudhoe Oil Pool only. To date, no formal plans have been announced by the field operators for the development of the Kuparuk and Lisburne reservoirs. Crude oil from the Prudhoe Oil Pool will be the only crude oil going through the pipeline for the first three years of operation.

Extensive analyses were performed on two crude samples from the Prudhoe Oil Pool. One sample was obtained from ARCO's Sag River State #1 (the Sadlerochit formation) and was analyzed by the Bureau of Mines. The other sample was also a Sadlerochit crude obtained from ARCO's Drill Site #1 and analyzed by ARCO.

TRANSSHIPMENT COSTS BETWEEN VALDEZ  
AND WEST COAST PORTS

Introduction

The principal market for North Slope Alaskan crude oil will be the West Coast of the United States because export exchange and swap arrangements of domestic crude oil for foreign crudes are barred by law. A number of questions arise about the ability of the West Coast market to absorb the entire production from Prudhoe Bay. Current estimates indicate that in 1978 the West Coast market will have a surplus of 300 to 600 MB/D. The surplus in 1982 may be as high as 600 to 800 MB/D.

The disposition of the surplus crude which will be available in the West Coast market has been analyzed by other studies and falls outside the scope of this assignment.

For the purpose of this study, the principal destination of the Prudhoe Bay Alaskan crude oil will be Puget Sound, San Francisco and the Los Angeles-Long Beach area even though significant amounts of North Slope Alaskan crude oil may find its way to the Gulf Coast.

United States Preference Trade Act

U.S. laws restrict the use of non-U.S. flag vessels in certain trades. For example, pursuant to Section 2 of the Shipping Act of 1916, cargoes transported by sea from one U.S. port to another must be carried in unsubsidized vessels of U.S. registry. These vessels must be owned by U.S. citizens and must have been built in the U.S. Furthermore, the

Merchant Marine Act of 1920 (the Jones Act) requires that cargo transported between domestic ports be in ships built and registered in the U.S. and manned with U.S. crews. The Jones Act further stipulates that companies with more than 25% foreign ownership are not considered to be U.S. companies for purposes of the Act.

#### Tanker Requirements and Availability

The U.S. tanker capacity which is required to deliver 2 MMB/D of North Slope production will range from 4.5 MMDWT to approximately 6 MMDWT, depending upon the disposition of Alaskan crude oil among the various regions of the U.S. The 4.5 MMDWT assumes that the North Slope production will be shipped to West Coast ports.

Given the dual considerations of economics of scale and port limitations, the preferred tanker sizes for North Slope oil trade are anticipated to range from about 50 MDWT to shallow draft 165 MDWT tankers. Unsubsidized tankers falling within this classification will reach approximately 4.5 MMDWT by 1979-1980. Of the 4.5 MMDWT, 3.2 MMDWT will be owned or controlled by North Slope oil companies who will lease rather than own their tankers for most of the tanker life. The remainder 1.3 MMDWT is owned by independent ship owners. Based on present commitments and tankers on order, enough tanker capacity will be available to transport the North Slope Alaskan crude oil to West Coast ports.

The tanker size distribution of the North Slope oil companies is presented in Table III-1.

Table III-1

TANKER SIZE DISTRIBUTION  
FOR  
TANKERS OWNED OR CONTROLLED BY  
NORTH SLOPE OIL COMPANIES

Number of Tankers	Size of Tankers MDWT	Status	Total Capacity MDWT
2	188	on firm order	376
4	165	on firm order	660
2	150	on firm order	300
1	150	on option	150
1	129	delivered	129
3	120	delivered	360
2	118	on firm order	236
1	118	on short term charter	118
2	81	delivered	162
2	81	on short term charter	162
3	75	delivered	225
4	70	delivered	280
1	52	delivered	<u>52</u>
			3,210
Independent Shipowners			1,300

The average size of tankers in the above distribution is estimated to be 115 MDWT.

## Tanker Charter Rates

Tanker charter rates are highly competitive. Prevailing market rates for time and voyage charters are subject to fluctuations from time to time depending on market conditions and supply and demand situation. Although long-term charter rates (usually defined as charters for periods in excess of three years) are also subject to supply and demand, the variations are generally not as extreme as the short-term market rates. Accordingly, the long-term market rates tend to be less volatile. Nevertheless, they also fluctuate from time to time and hence are not suitable as a basis for determining the cost of transshipment. For the purpose of this analysis, the cost of transshipment will be computed by:

- depreciating the cost of the tanker over its useful life after allowing a rate of return on the investment, plus
- the cost of operating the tanker.

## Cost of Transshipment from Valdez to West Coast Ports

The cost of transshipment from Valdez to West Coast ports consists of capital charges related to tanker construction plus applicable marine operating costs.

### A. Cost of Tanker Construction

The cost of large crude carriers built in American shipyards has risen from around 200 \$/DWT in 1970 to over 500 \$/DWT on current orders. This cost does not include interest during construction which averages under 10% of the cost of construction.

Tankers which were built before the recent rapid rise in construction costs will have a distinct competitive advantage. The average construction cost for the entire Valdez to West Coast fleet is estimated to be 450 \$/DWT plus 40 \$/DWT for interest during construction. To arrive at transportation costs in ¢/B, the construction costs are depreciated over the life of the tanker, assuming several rates of return (for sensitivity purposes) and taking into account the length of the voyage between Valdez and various West Coast ports.

The following assumptions were used to compute the annual revenues and hence the capital charges per barrel required to yield various rates of return on the invested capital in tanker construction:

- Investment tax credit = 10%.
- For federal income tax purposes, tanker is depreciated over 14.5 years using double declining balance.
- Tanker life is 25 years.
- Federal income tax is 48%.

The computed capital charges are shown in Tables III-2 and III-3.

## TRANS ALASKA PIPELINE SYSTEM

Basic Facts

The trans-Alaska pipeline is just over 801 miles in length, of which about 375 miles will be buried and the remainder will be elevated. Current plans call for an initial capacity of 600 MB/D when the line is first completed in mid-1977, increasing to an ultimate capacity of 2 MMB/D in three stages. In the first stage, line capacity will be boosted to 1.2 MMB/D by late '77 or early '78. The capacity will be further boosted to 1.5 MMB/D in '79. Boosting the capacity further to 2 MMB/D must be coordinated with the development of speculative reserves (see Field Development Plans). Some estimates indicate that the pipeline via "looping", which employs added pipe and pump stations at various points along the line where the grade requires it, could handle 2.5 MMB/D. The Valdez terminal will have a ship-loading capacity of 80 to 110 MB/H, and can accommodate tankers of 195 MDWT. For a line capacity of 1.2 MMB/D, the storage capacity will be met through 18 tanks with 510 MB capacity each. Four berths will be required for the 1.2 MMB/D throughput, with a fifth berth to be added upon the increase in line capacity.

## Trans Alaska Pipeline Ownership

<u>Company</u>	<u>% of line owned</u>
SOHIO Pipe Line Company	33.34
BP Pipelines, Inc.	15.84
ARCO Pipeline Company	21.00
Exxon Pipeline Company	20.00
Mobil Alaska Pipeline Company	5.00
Union Alaska Pipeline Company	1.66
Phillips Petroleum Company	1.66
Amerada Hess Corporation	1.50

## TAPS Agreement

Duration of initial team: 30 years

Form of ownership: undivided joint interest

Transfer of ownership:

- permissible for cash
- partners have first purchase rights

Expansion from 1.2 MMB/D to 2.0 MMB/D

- any participant may propose
- other participants may acquire proportionate share or decline
- each partner has option to acquire share for 2 years after expansion

## Construction Costs

The estimated costs of pipeline construction for 1.2 MMB/D design capacity is 7.7 billion dollars. This estimate includes the construction costs for the Valdez terminal, the fuel line, pump stations, and pumping plants. The estimated construction costs by year of expenditure and by cost item are shown in Tables IV-1 and IV-2.

Table IV-1

ESTIMATED CONSTRUCTION COSTS OF  
TRANS ALASKA PIPELINE SYSTEM  
BY YEAR OF EXPENDITURE  
 (For 1.2 MMB/D Design Capacity)

<u>Year</u>	<u>Expenditures</u> MM\$
1969	35
1970	180
1971	109
1972	49
1973	47
1974	857
1975	2,772
1976	2,698
1977	765
1978	188
Total	<u>7,700</u>

Table IV-2  
TRANS ALASKA PIPELINE SYSTEM

CONSTRUCTION COSTS

( MM \$ )

Estimated Costs  
 for 1.2 MMB/D  
 (Design Capacity)

1. Alyeska Corporate	940.0
2. Bechtel - General	127.0
3. Pipeline - General	696.1
4. Pipeline Sections	1,353.6
5. Fuel Line	26.1
6. Mainline Pipe & other Permanent Materials	753.1
7. Pipeline & Roads - General	1,696.3
8. Roads - General	20.2
9. Roads	114.0
10. Yukon River Crossing	20.6
11. Fluor	171.2
12. Stations and Terminal - General	.1
13. Stations - General	14.8
14. Pump Stations	618.3
15. Topping Plants	21.1
16. Gate Valves	30.1
17. Mainline Refrigeration	5.0
18. Terminal - General	354.4
19. Terminal	738.0
Total Estimated Construction Costs	<u>\$ 7,700.0</u>

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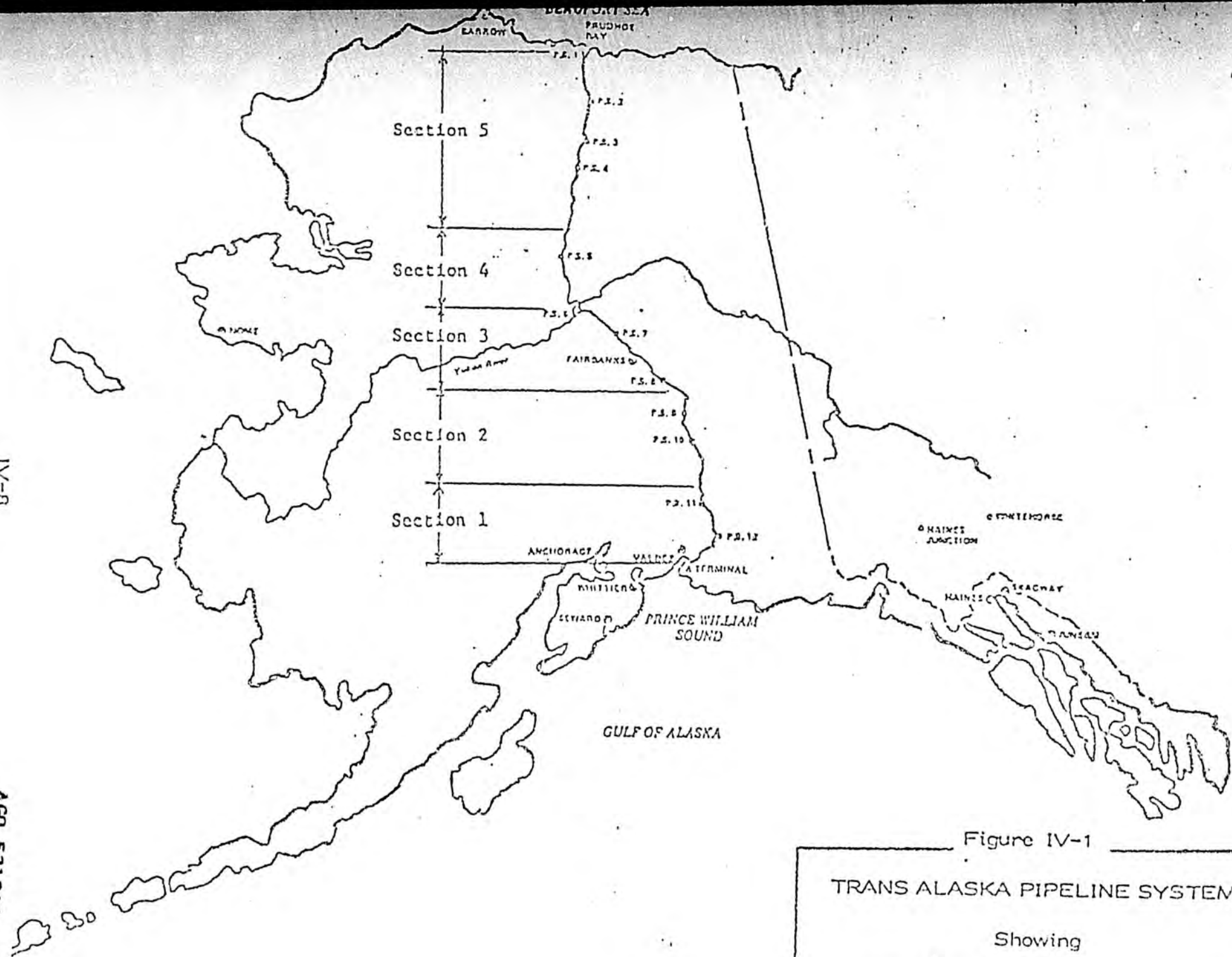


Figure IV-1  
TRANS ALASKA PIPELINE SYSTEM  
Showing  
Pump Stations and Line Sections



## Tariff Computation

The Prudhoe Bay Field development plans presented in this report identify three possible alternatives. Each alternative results in a different rate of production and throughput for the pipeline. Consequently, the computed tariff rates are different for each development plan. The tariffs were computed for each case for the years 1977 - 1994 according to the ICC and Justice Department guidelines as outlined in the Assumptions. After 1994, and due to the rapid decline in the field production rate, the computed tariff would have to be increased sharply to yield to the owners 7% on the valuation of the pipeline. It was therefore assumed that by 1994, either new fields would have been discovered or the owners would accept less than the 7% allowed by the ICC. From 1995 on, the tariff was increased at 10 ¢/B annually. This assumption has little effect on the recommended crude price, since the rate of return is computed on the investment in the field and pipeline. The three cases for which the tariff was computed are summarized below.

Case 1: Field development in this case is limited to Prudhoe Oil Pool. The field production rate was limited to 1.5 MMB/D and held at that rate through 1985, after which it begins to decline. The pipeline capacity was expanded in 1979 from 1.2 MMB/D to 1.5 MMB/D. The cost of the expansion was estimated at 520 MM\$ plus 50 MM\$ for construction interest. This brings the total estimated cost of the pipeline for 1.5 MMB/D capacity to 8,220 MM\$ plus 1,350 MM\$ for construction interest. The tariff for Case 1 in 1976 dollars varies between 3.45 and 5.40 \$/B.

Case II: Field development in this case includes a lower estimate of the reserves of the Kuparuk and Lisburne Oil Pools. The rate of throughput for the pipeline increases to 1.77 MMB/D and is held through 1985, after which it begins to decline. It was necessary, therefore, to increase the pipeline capacity to the next level of 2 MMB/D. The estimated cost for increasing the pipeline capacity from 1.5 to 2.0 MMB/D is 500 MM\$ plus 50 MM\$ for construction interest. The total cost of the line is estimated to be 8,720 MM\$ plus 1,400 MM\$ for construction interest. The increase in throughput for this case outweighs the increase in cost required to increase the line capacity. Therefore, it results in a lower tariff than in Case I. The tariff for Case II in 1976 dollars varies between 3.10 and 5.60 \$/B.

Case III: The field development in this case includes the upper estimate of the reserves of the Kuparuk and Lisburne Oil Pools. The rate of throughput for the pipeline increases to 1.915 MMB/D and is held through 1985, after which it begins to decline. This case requires no additional investment in TAPS over Case II. However, because of the increased rate of throughput the tariff in 1976 dollars varies between 2.90 and 5.60 \$/B.

## TRANS ALASKA PIPELINE SYSTEM

### ASSUMPTIONS FOR TARIFF COMPUTATION (All Costs in Billion Dollars)

1. Cost of construction for 1.2 MMB/D design capacity = 7.70
2. Construction interest for (1) above = 1.30
3. Cost of expansion to 1.5 MMB/D = .52
4. Construction interest for (3) above = .05
5. Operating costs = .274 \$/B
6. State of Alaska corporate income tax = 9.4 %
7. State of Alaska ad valorem tax based on economic value of pipeline = 2 %
8. Debt to capital ratio = .85
9. Interest on debt = 9.0 %/annum
10. Debt is retired in equal installments over a 25-year period.
11. For rate determination, pipeline depreciation is normalized (i.e. straight line) over 26.5 years. Federal and state income taxes allowed in rate determination are based on normalized depreciation. [Reference: ICC Docket No. 35533; William Bros. Pipeline Co., October 10, 1975]
12. The ICC valuation base declines at 6% per annum.
13. The maximum profit permitted on the ICC valuation base is 7% per annum.
14. For actual federal income tax, the line is depreciated using double declining balance over 17.5 years.
15. Federal corporate income tax = 48%
16. Investment tax credit = 10%

Table IV-3

TRANS ALASKA PIPELINE SYSTEM  
COMPUTED TARIFF AND PIPELINE ECONOMICS

CASE I: LINE CAPACITY 1.5 MMB/D  
(Field Development Limited to Prudhoe Oil Pool)

Year	Throughput		Tariff ¢/B	Gross Revenue MM\$	Operating Costs MM\$	State Taxes		Federal Income Tax MM\$	Capital Investment MM\$
	MM/D	MMB/Y				AdValorem MM\$	Corporate MM\$		
1969									35
70									180
71									109
72									49
73									47
74									850
75									2772
76									2098
77	600	148	540	788	40	53			765
78	1200	438	540	2095	120	115			188
79	1400	511	485	2478	140	103			520
1980	1500	540	435	2384	150	102		104	
81	1500	540	415	2274	150	93		329	
82	1500	548	395	2165	150	90		337	
83	1500	549	380	2032	150	84		344	
84	1500	543	365	2000	150	79		347	
85	1500	543	345	1891	150	75		336	
86	1400	513	345	1701	142	70		334	
87	1305	476	350	1717	131	66		329	
88	1210	442	365	1612	121	62		322	
89	1110	405	380	1539	111	58		322	
1990	1034	377	385	1455	104	55		314	
91	982	347	395	1375	95	51		308	
92	870	319	410	1304	87	48		304	
93	801	292	420	1231	80	45		296	
94	732	267	430	1148	74	43		284	

Pre-1976 costs expressed in actual dollars (i.e., money of the day).  
Post-1976 costs and revenues expressed in 1976 dollars.

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Table IV-4

TRANS ALASKA PIPELINE SYSTEM  
COMPUTED TARIFF AND PIPELINE ECONOMICS

CASE II: LINE CAPACITY 2.0 MMB/D  
(Field Development Includes Lower Estimate of Kuparuk and Lisburne Pools)

Year	Throughput		Tariff ¢/B	Gross Revenue MM\$	Operating Costs MM\$	State Taxes		Federal Income Tax MM\$	Capital Investment MM\$
	MM/D	MMB/Y				Ad Valorem MM\$	Corporate MM\$		
1969									35
70									180
71									109
72									49
73									47
74									853
75									2772
76									2698
77	800	146	560	810	40	53			765
78	1200	438	560	2453	120	115	50		702
79	1500	548	475	2603	150	122	73		500
1980	1600	594	430	2511	160	125	74	61	
81	1720	629	335	2418	172	117	77	357	
82	1750	642	360	2315	176	110	78	369	
83	1770	646	340	2260	176	104	77	354	
84	1770	646	325	2100	177	90	76	353	
85	1770	646	310	2006	177	92	76	350	
86	1655	604	315	1903	168	86	76	349	
87	1535	560	325	1823	154	81	75	345	
88	1435	524	330	1729	144	76	74	344	
89	1325	484	340	1621	133	72	74	341	
1990	1234	450	345	1556	123	67	72	334	
91	1142	417	350	1460	114	63	70	322	
92	1040	380	365	1387	104	59	69	319	
93	958	349	375	1300	96	56	67	312	
94	872	310	385	1185	87	53	62	285	

Pre-1976 costs expressed in actual dollars (i.e., money of the day).  
Post-1976 costs and revenues expressed in 1976 dollars.

IV-21

AGO 531254

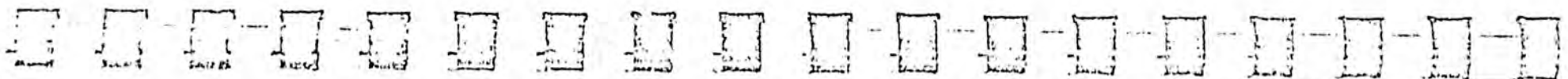
Table IV-5

TRANS ALASKA PIPELINE SYSTEM  
COMPUTED TARIFF AND PIPELINE ECONOMICS

CASE III: LINE CAPACITY 2.0 MMB/D  
(Field Development Includes Upper Estimate of Kuparuk and Lisburne Pools)

Year	Throughput		Tariff ¢/B	Gross Revenue MM\$	Operating Costs MM\$	State Taxes		Federal Income Tax MM\$	Capital Investment MM\$
	MB/D	MMB/Y				Ad Valorem MM\$	Corporate MM\$		
1969									35
70									160
71									100
72									49
73									47
74									550
75									2772
76									2063
77	800	140	500	818	40	53			765
78	1200	438	500	2453	120	115		56	708
79	1500	548	475	2503	150	122		73	500
1980	1000	584	430	2511	173	125		61	
81	1704	655	370	2424	179	117		350	
82	1859	679	340	2309	186	110		352	
83	1909	670	325	2207	186	104		353	
84	1915	659	305	2135	192	99		351	
85	1915	600	250	2030	192	92		354	
86	1800	657	290	1941	180	86		350	
87	1677	612	300	1809	168	81		341	
88	1574	575	300	1725	157	76		336	
89	1408	532	310	1652	146	72		334	
1990	1357	495	315	1562	136	67		331	
91	1259	460	320	1472	126	63		322	
92	1145	418	330	1379	114	59		312	
93	1052	384	340	1306	105	56		306	
94	950	350	355	1243	96	53		305	

Pre-1976 costs expressed in actual dollars (i.e., money of the day).  
Post-1976 costs and revenues expressed in 1978 dollars.



## Some Comments on Tariff Computation

Gross Revenue = throughput X tariff.

Operating Costs are based on the estimated manpower required to operate and maintain the line. Alyeska and TAPS owners are still in the process of developing an operating budget for TAPS and could not confirm or infirm our estimate.

State Corporate Income Tax = .094 of taxable income from the pipeline.

Discussions with Alaska Department of Revenue indicate that the State of Alaska applies allocation and apportionment in multi-state taxation. The application of multi-state taxation would require estimating total corporate income by pipeline owner from all activities and allocating it back to each activity based on certain allocation formulas. This approach could not be followed here because it would be unrealistic to estimate the future corporate income of each TAPS owner for the entire life of the project.

Tables IV-3, IV-4, and IV-5 present the computation of the tariff, gross revenue, operating costs, State of Alaska ad valorem and corporate income taxes, federal income tax and capital investment. These results were merged with the results of calculations from Prudhoe Bay and used to calculate a rate of return on the investment in the field and pipeline.

A communication received from a North Slope owner shortly before going to print estimates the operating costs at 25 ¢/B higher than our estimate. Since TAPS' operating costs are passed in toto to the tariff, and since this

change increases the real rate of return on the investments in TAPS and the field by 6 basis points only, it was possible to account for this change without repeating the entire computation and analysis.

Average Tariff for First 10 Years of Pipeline Operation

	<u>\$/B</u>
Case I	4.50
Case II	4.30
Case III	4.20

## Effects of Inflation on Pipeline Tariff

Inflation impacts the tariff in three ways:

- The valuation base at any given time is affected by the rate of inflation, which determines the replacement cost of the line.
- The interest charges on the debt are also affected by the rate of inflation. Portions of the debt will be refinanced at maturity at interest rates which depend on the rate of inflation.
- The future operating costs of the line will also depend on the rate of inflation and will directly impact the tariff.

### Pipeline Tariffs in 1987 at 7% Inflation

	<u>\$/B</u>
Case I	4.80
Case II	4.35
Case III	4.05

## PRUDHOE BAY FIELD

## RESERVES AND DEVELOPMENT PLANS

Introduction

The Prudhoe Bay Oil Field is located on the flat-lying coastal plain of the Alaskan North Slope about 120 miles north of the Brooks Range (see Figure V-1). The North Slope is 600 miles long from the Canadian border to the Chukchi Sea and up to 200 miles wide from the Brooks Range to the Arctic Ocean. At the western part of the North Slope is National Petroleum Reserve #4, and the eastern part of the Slope is occupied by the National Wildlife Refuge. The area between NPR #4 and the Wildlife Refuge has been actively explored since the late 1950's. This effort culminated in the discovery of Prudhoe Bay Field in 1968.

In the Prudhoe Bay Field area, basement is encountered at 12,000 feet. Overlying the basement rock are sequences of sedimentary rocks. In ascending order, the recognized formations are: the Kekiktuk conglomerate, Kayak shale, Itkilyarriak formation, and the Lisburne group carbonates, which contain the Lisburne Oil Pool, the lowest defined pool in the Field. Overlying these are the Sadlerochit formation, Shublik formation, and Sag River sandstone, which together contain the most important oil pool in the Prudhoe Bay Field, officially designated as the Prudhoe Oil Pool. The Kingak shale occurs next. The youngest unit in the lower sequence is the Kuparuk River sands, containing the shallowest defined oil pool in the Field. The Lisburne Oil Pool extends east of the Prudhoe Oil

Pool, and the shallower Kuparuk Oil Pool extends over a broad area to the west of the Prudhoe Oil Pool.

Following the discovery of Prudhoe Bay Field in 1968, the State of Alaska held a lease sale and received just over 900 million dollars in lease bonuses. Of that amount, 361 million dollars were spent on the area currently encompassing the Kuparuk River Oil Pool, the Prudhoe Oil Pool and the Lisburne Oil Pool as defined by the Division of Oil and Gas, Department of Natural Resources, State of Alaska (see Figure V-2).

Step-out drilling proceeded to delineate the limits of the Field. As of December 1975, 88 production wells had been drilled in Prudhoe Oil Pool, 55 of which are located on the west side operated by BP and 33 of which are located on the east side operated by ARCO. To satisfy initial crude oil supply demands for the trans-Alaska pipeline, current activity in Prudhoe Bay is directed toward development of this reservoir. Under State of Alaska regulations, the entire Prudhoe Bay Field will be developed as a unit and not by individual companies holding leases to avoid duplication of facilities and to ensure maximum efficient production with maximum environmental protection.

## Prudhoe Bay Field Reserves

### 1. Prudhoe Oil Pool

The Prudhoe Oil Pool has been studied and reported on by the State of Alaska, Department of Natural Resources, Division of Oil and Gas; and by the Federal Energy Administration in a study dated December 31, 1974. The oil and gas reserves in the Prudhoe Oil Pool are summarized in Table V-1 based on discussions with the field operators and after reviewing the above-mentioned studies.

Table V-1

PRUDHOE OIL POOL  
OIL AND GAS RESERVES

	Stock Tank Oil & Condensate MMMB	Solution Gas TCF	Gas Cap Gas TCF
Hydrocarbons, In Place*	22.9	13.9	26.6
Recoverable**	9.0 to 9.2	8.0	18.6
% Recovery	39 to 40	58	70

Initial average producing GOR = 750 CF/B

Gas contains 12.0% CO<sub>2</sub>

\* State of Alaska - Division of Oil & Gas

\*\* Various sources

(Recoverable oil includes .5 MMMB of condensate.)

## 2. Kuparuk and Lisburne Oil Pools

In contrast to the Prudhoe Oil Pool, no engineering studies have been released on the Kuparuk and Lisburne Oil Pools. In fact, little information other than the press releases concerning the results of well tests is available on these oil pools. Therefore our estimate of reserves in the Kuparuk and Lisburne Oil Pools must be classified as speculative.

Speculative recoverable reserves from other reservoirs in the Prudhoe Bay area including secondary recovery are in the order of 1.3 to 2.1 billion barrels. Most of these reserves occur in the Kuparuk sand reservoirs to the west of the large Sadlerochit sand reservoir and in the Lisburne lime reservoirs which lie primarily under the gas cap of the large Sadlerochit reservoir.

Based upon announced well tests, it could be postulated that the Kuparuk sands are from 20 feet to 60 feet thick and the area could be three to five townships. The oil is in the 21° to 23° API gravity and the gas-oil ratio is in the order of 300 to 400 SCF/B. Using an average porosity of 23% and a normal water saturation of 25% and formation volume factor of 1.19, there would be 1125 stock tank barrels of oil in place per acre foot.

To maximize recovery, artificial recovery methods using waterflood or waterflood plus CO<sub>2</sub> injection would have to be started at the same time as production. Total recovery from the Kuparuk sand reservoirs could be postulated to be in the range of 630 to 1360 MMB of stock tank oil. Tests indicate that wells have a producing capacity in the 1000 to 2500 B/D rate.

Announced tests of Lisburne lime wells have indicated thicker net

Table V-4

Summary of Speculative Reserve Estimates

	Kuparuk MMBbls	Lisburne MMBbls	Total MMBbls
Lower Estimate w/artificial recovery	826	469	1295
Higher Estimate w/artificial recovery	1358	714	2072

## Development Plans for Prudhoe Bay Field

### 1. Prudhoe Oil Pool

As of December 1975, 55 wells have been drilled in the area operated by BP and 33 wells have been drilled in the area operated by ARCO. Current development plans indicate that a total of about 130 producing wells will have been drilled and fully equipped for production by midyear 1977 (start-up date for the Alyeska Pipeline). It is anticipated that these wells will produce 1,200,000 BOPD (producing capacity will be slightly larger). These wells will be drilled in that part of the field where there is approximately 200 feet of oil column in the Sadlerochit sand. Completions will be made in that part of the sand to minimize water production and the production of gas from the gas cap. Initially the well spacing will be 320 acres per well.

It is planned that by midyear 1978 enough additional wells (approximately 70) will have been drilled so that the east side of the field (ARCO-operated) will have a producing capacity of 960,000 BOPD and the west side (BP-operated) will have a capacity of 900,000 BOPD for a total of 1,860,000 BOPD. The total of producing oil wells in the field at this time will be approximately 200.

By mid-1979 and no later than January 1, 1980 additional wells will be drilled to attempt to bring the productive capacity of the field to 2,000,000 BOPD. However, the field will be produced at a rate of 1,500,000 to 1,600,000 BOPD in order to maintain a flat rate to the pipeline for several years (estimated 7-plus). As in the operations of most

fields, where the water drive is not 100 per cent effective in maintaining reservoir pressure, well productivity should start to decline during this 7-plus year period and gas-oil ratios should start increasing. Ultimately 500 or more oil wells may be required in the oil column, reducing the well spacing to 160 acres per well or less. This will be required for optimum recovery of oil and gas and prudent operation of the oil pipeline.

Initially all gas produced along with the oil will be reinjected in the gas cap of the reservoir and will continue until a gas pipeline is constructed to the Prudhoe Bay Field. The earliest date forecasted for completion of an Alaskan gas transportation system (and this would require the highest priority for material and supplies) would be mid-1981. A more likely date would be mid-1982 or later.

Due to the characteristics of the sediments and the problem of heavy oil at the base of the sand in certain areas, the oil rim is only open to the aquifer in 50 to 70 per cent of the field. (See description of lower zone on page 13, June 1974, State of Alaska - Division of Oil and Gas, Report on in place volumetric determination of reservoir fluids, Sadlerochit formation, Prudhoe Bay Field.) In all probability then, water injection into the reservoir will not be necessary until mid-1982, i.e. when gas sales would be started and only in quantities equal to the reservoir voidage resulting from producing the gas cap.

PRUDHOE BAY FIELD

PRUDHOE OIL POOL

DEVELOPMENT AND PRODUCTION PLANS

ASSUMPTIONS:

1. Alyeska Pipeline will start operations 7-1-77.

(a) Initial rate will be 300,000 BPD.

(b) After 9-1-77 the rate will be increased to 600,000 BPD.

(c) After 10-1-77 the rate will be increased to 1,200,000 BPD.

(d) After 1-1-79 the rate will be increased to 1,500,000 BPD.

Sufficient rigs (probably 4 or more) must be operated to maintain this rate until 1985.

(e) After 1-1-80 the rate may be increased to 1,900,000 BPD.

(This is speculative and will be dependent upon added production from Kuparuk sand reservoir and the Lisburne lime reservoir.)

2. The productive capacity of the Prudhoe Oil Pool (crude oil and condensate)

(a) More than 120 oil producing wells will have been completed by 7-1-77, sufficient gas injection wells will have been completed and gas injection facilities installed.

(b) Gas sales will have been started on 1-1-83 at the rate of 2.0 billion cubic feet per day. Gas from the gas cap will produce 30 barrels of condensate per million cubic feet of reservoir gas.

- (c) It will be necessary to drill sufficient gas wells in the gas cap to have a deliverability in excess of one billion cubic feet per day in order to have 2.0 billion cubic feet per day available for the gas pipeline by 1-1-83.
- (d) Pressure maintenance by water injection starts 1981-82.

## PRUDHOE BAY FIELD

## COSTS, WELL HEAD PRICES, AND ALASKA NATIVE FUND

Finding Costs

The finding costs of Prudhoe Bay Field consist of two types:

1. Expenditures on exploratory drilling, lease bonuses and rentals, geological and geophysical activity from the inception of industry activity on the North Slope in 1959 until the field discovery by Prudhoe Bay State #1 and confirmation by Sag River State #1 in 1968. Industry's expenditures on the North Slope (specifically the area between NPR #4 and the Wildlife Refuge) were estimated from the Joint Association Survey's annual publications and are presented in Table VI-1.

It can be stated that exploration ventures, especially of the type analyzed here, i.e. in virgin basins, do not usually result in discoveries. Hence, successful exploratory ventures should carry the cost of unsuccessful exploratory effort. A "risk multiplier R" can be defined such that if "S" exploratory ventures result in one commercial discovery, then the exploratory costs of the successful venture should be weighted by the risk multiplier "R" to account for the cost of the other ventures. However, the quantification of this argument presents some difficulties. For if "S" represents the inverse of the success ratio in exploration activity, then "R" should take into account the Internal Revenue Code which permits the explorationist to write off the cost of the unsuccessful ventures. Thus,  $R = 1 + .5(S - 1)$ ; i.e. a success ratio of one in seven results in a risk multiplier "R" of 4.

Another approach, in lieu of the risk multiplier, would be to interpret the computed rate of return in terms of the nature of the exploratory venture. Thus, exploratory activity in a virgin basin should yield a higher rate of return than exploratory effort in a mature basin where the probability of success is comparatively high.

There is still an alternate approach, however, which could be used in this case. Specifically, the transaction between Sohio and British Petroleum which involved about half of the reserves of Prudhoe Bay could be analyzed to establish the value assigned to the undeveloped reserves by the participants in the transaction.

Table VI-1, which presents our estimate of the industry's expenditures on the North Slope from 1959 until discovery of Prudhoe Bay, was not modified to reflect a risk multiplier and the numbers in it are "money of the day" and have not been converted to 1976 dollars.

2. In 1969 after the discovery of Prudhoe Bay Field, the State of Alaska held a lease sale and received over 900 MM\$ in lease bonuses. Of that amount, 361 MM\$ were spent on the area covered by the Kuparuk, Prudhoe and Lisburne Oil Pools as defined by the State of Alaska, Division of Oil and Gas. This 361 MM\$ is included in Table VI-1 as part of Prudhoe Bay finding costs. However, it cannot be considered as a risk investment and does not receive a risk multiplier since it was made after field discovery.

## Well Head Prices and Gross Revenue

The ceiling on Prudhoe Bay crude is set by the price of Saudi Arabian crude on the West Coast market. The price of Saudi crude to a West Coast refiner, exclusive of entitlements, consists of:

	<u>\$/B</u>
Arabian crude (FOB Ras Tanura)	11.51
Tanker tariff to Long Beach	1.33
Crude import fees	.21
Terminal charges	<u>.10</u>
	13.15
Average transshipment and terminal charges from Valdez to West Coast	<u>.76</u>
Ceiling price of Prudhoe Bay crude at Valdez	12.39

Based on the ceiling price of Prudhoe Bay crude at Valdez and on the average pipeline tariff during the first 10 years of service, the ceiling well head price in 1976 dollars for the first 10 years of production averages 7.90 \$/B for Case I, 8.10 \$/B for Case II, and 8.20 \$/B for Case III. The nominal ceiling price of Prudhoe Bay crude at the well head and at Valdez is to be adjusted quarterly to reflect the effects of the rate of inflation on crude prices.

The determination of equitable prices for Prudhoe Bay crude at Valdez is sensitive to the risk multiplier applied to industry's expenditures on the North Slope from 1959 until discovery of Prudhoe Bay in 1968 (see

Chapter VII). A risk multiplier of between 3.0 and 4.5 is consistent with industry's expenses in wildcat activities during the mid-1960's. For a risk multiplier of 3 and a crude price of 11.50 \$/B at Valdez, the DCF, after tax, real rate of return on the investments in Prudhoe Bay Field and in TAPS is equal to 12%. Similarly, for a risk multiplier of 4.5 and a crude price of 12.40 \$/B at Valdez, the DCF, after tax, real rate of return on the investments in Prudhoe Bay Field and TAPS is equal to 12%. An equitable price for Prudhoe Bay crude at Valdez in 1976 dollars falls in the range of 11.50 to 12.40 \$/B. Based on the price at Valdez, equitable prices at the well head are as follows:

Case I (only Prudhoe Oil Pool is developed)	7.00 - 7.90 \$/B
Case II (Prudhoe Oil Pool + lower estimate of Kuparuk and Lisburne)	7.20 - 8.10 \$/B
Case III (Prudhoe Oil Pool + upper estimate of Kuparuk and Lisburne)	7.30 - 8.20 \$/B

The prices are in 1976 dollars and are to be adjusted for inflation to yield 12% return.

Projections of ceiling well head prices and gross revenue in 1976 dollars for Cases I, II, and III are presented in Tables VI-5, VI-6, and VI-7. The gross revenue projections include revenue from gas sales starting in 1983. The well head price of gas before CO<sub>2</sub> removal is assumed to be .53 \$/MCF in 1976 money.

PRUDHOE BAY FIELD

WELL HEAD PRICE, ROYALTY AND TAX PAYMENTS

CASE I: Field Development Limited to Prudhoe Oil Pool

Year	Well Head Price \$/B	Alaska Native Fund Payment MM\$	State Royalty MM\$	Severance Tax MM\$	AdValorem Tax MM\$	Corporate income tax	
						State MM\$	Federal MM\$
77	6.99	20	107	68	42	16	
78	6.99	61	321	206	54	168	536
79	7.54	77	405	258	61	226	1010
80	8.04	88	463	293	67	265	1182
81	8.24	90	474	298	75	260	1135
82	8.44	92	486	304	87	263	1153
83	8.59	72	565	332	97	296	1309
84	8.74		647	334	108	301	1335
85	8.94		661	338	117	308	1398
86	8.94		627	317	121	299	1382
87	8.79		571	283	113	270	1248
88	8.74		531	260	105	253	1171
89	8.59		483	235	98	230	1063
90	8.54		451	221	91	214	992
91	8.44		414	203	84	197	911
92	8.29		378	185	78	179	827
93	8.19		344	171	73	161	746
94	8.09		312	157	68	145	670
95	7.99		280	142	63	127	589
96	7.89		247	127	59	113	521
97	7.79		222	113	55	99	457
98	7.69		195	99	51	84	389
99	7.59		168	84	47	69	319
2000	7.49		145	72	44	56	260
01	7.39		122	60	41	44	202
02	7.29		104	51	38	33	153

Post-1976 costs and revenues expressed in 1976 dollars.

## PRUDHOE BAY FIELD

## WELL HEAD PRICE, ROYALTY AND TAX PAYMENTS

CASE II: Field Development Includes Prudhoe Oil Pool +  
Lower Estimate for Kuparuk and Lisburne Pools

Year	Well Head Price \$/B	Alaska Native Fund Payment MM\$	State Royalty MM\$	Severance Tax MM\$	Ad Valorem Tax MM\$	Corporate income tax	
						State MM\$	Federal MM\$
77	6.79	20	304	65	42	14	
78	6.79	50	312	198	54	140	352
79	7.64	84	440	277	70	222	939
80	8.03	94	496	309	86	252	1060
81	8.54	107	563	347	105	279	1166
82	8.79	113	593	360	128	289	1223
83	8.99	23	756	390	148	327	1409
84	9.14		791	392	166	350	1548
85	9.29		803	395	177	359	1618
86	9.24		751	363	181	339	1357
87	9.14		693	331	180	312	1442
88	9.03		649	308	168	295	1365
89	8.99		597	284	156	272	1258
90	8.94		556	265	145	254	1176
91	8.89		517	246	135	237	1098
92	8.74		468	226	125	214	991
93	8.64		427	207	117	194	897
94	8.54		386	188	109	174	809
95	8.44		345	169	101	153	708
96	8.34		308	151	94	137	633
97	8.24		276	136	87	121	558
98	8.14		245	121	81	104	480
99	8.04		212	105	76	86	398
2000	7.94		185	92	70	71	331
01	7.84		157	78	65	68	316
02	7.74		137	68	61	57	265

Post-1976 costs and revenues expressed in 1976 dollars.

PRUDHOE BAY FIELD

WELL HEAD PRICE, ROYALTY AND TAX PAYMENTS

CASE III: Field Development Includes Prudhoe Oil Pool +  
Upper Estimate for Kuparuk and Lisburne Pools

Year	Well Head Price \$/B	Alaska Native Fund Payment MM\$	State Royalty MM\$	Severance Tax MM\$	Ad Valorem Tax MM\$	Corporate income tax	
						State MM\$	Federal MM\$
77	6.79	20	104	65	42	13	
78	6.79	59	312	198	54	127	260
79	7.64	84	440	275	75	203	821
80	8.09	94	496	306	98	228	917
81	8.69	114	598	366	124	276	1116
82	8.99	122	641	385	153	292	1207
83	9.14	7	825	411	179	324	1355
84	9.34		872	427	204	374	1654
85	9.49		885	428	213	386	1735
86	9.49		836	397	219	369	1686
87	9.39		775	353	219	341	1578
88	9.39		731	341	203	327	1514
89	9.29		674	315	189	302	1399
90	9.24		628	294	176	283	1308
91	9.19		585	273	164	265	1225
92	9.09		531	247	152	240	1109
93	8.99		484	224	142	217	1005
94	8.84		436	202	132	194	897
95	8.74		390	180	122	170	786
96	8.64		347	160	114	151	700
97	8.54		314	144	106	134	622
98	8.44		277	127	98	115	533
99	8.34		241	110	92	96	442
2000	8.24		211	96	85	80	369
01	8.14		182	82	79	75	349
02	8.04		158	71	74	63	291

Post-1976 costs and revenues expressed in 1976 dollars.

Royalty Payments and The Native Claims Settlement Act

Under Public Law 92-203 of December 18, 1971, "Native Claims Settlement Act":

Section 6(a) There is hereby established in the United States Treasury an Alaska Native Fund into which the following monies shall be deposited:

1. . . .

2. . . .

3. \$500,000,000 pursuant to the revenue sharing provision of Section 9.

Section 9(b) . . . the State shall pay into the Alaska Native Fund from the royalties, rentals, and bonuses hereafter received by the State, a royalty of 2 per centum upon the gross value of such minerals produced or removed from such lands.

Thus, of the royalty of 12.5% received by the State of Alaska, 2% will be paid into the Alaska Native Fund established in the United States Treasury until the total paid in the Fund amounts to \$500,000,000. The payments due the Alaska Native Fund and the State of Alaska royalty are presented year by year in Tables VI-5, VI-6, and VI-7. In all three development plans, the payments in the Alaska Native Fund will be completed before the end of 1983. In fact, the payments into the Fund will probably be completed before the end of 1982 since they will be made in nominal dollars instead of 1976 dollars.

## State of Alaska Severance and Ad Valorem Taxes

The State of Alaska receives severance tax on a percentage of gross value at the well head (less royalty) or on a per barrel basis, whichever is higher. For Prudhoe Bay Field at the well head prices under consideration, the percentage severance tax applies and is computed according to the following table:

Average Production Rate per Well B/D	Severance Tax %
0 - 300	5
301 - 1000	6
over 1000	8

The ad valorem tax is equal to 2% on capital investment in exploration and production properties assessed on replacement costs less depreciation, and is shown in Tables VI-5, VI-6, and VI-7.

## State of Alaska and Federal Corporate Income Tax

Tax rates of 9.4% and 48% were used for the State and Federal corporate income taxes, respectively.

PRICING CONSIDERATIONS

DCF, AFTER TAX, REAL RATE OF RETURN

AND SENSITIVITY ANALYSES

Effect of Throughput on Rates of Return

Three alternate field development plans were considered:

Case I: Development plans were limited to Prudhoe Oil Pool and TAPS' throughput capacity to 1.5 MMB/D. The pipeline operates at capacity for nearly seven years.

Case II: Development plans were expanded to include lower estimate of reserves and producing capacity of Kuparuk and Lisburne Oil Pools. TAPS' throughput capacity increases to the next level of 2 MMB/D. Rate of throughput for TAPS increases to 1.77 MMB/D. In this Case, Prudhoe Oil Pool is produced at rates up to 1.6 MMB/D instead of 1.5 MMB/D as in Case I.

Case III: Development plans include upper estimate of reserves and producing capacity of Kuparuk and Lisburne Oil Pools. TAPS' throughput capacity is 2 MMB/D. Rate of throughput for TAPS increases to 1.915 MMB/D. Prudhoe Oil Pool is produced as in Case II.

The estimated development costs of the speculative Kuparuk and Lisburne Oil Pools are considerable higher than Prudhoe Oil Pool. On the other hand, the estimated incremental investment required to increase TAPS' capacity to accommodate the production from the Kuparuk and Lisburne Oil Pools is modest compared with the initial investment required for the

1.5 MMB/D of TAPS' throughput capacity. As a result, the real rate of return on the investments in the field and pipeline is relatively insensitive to the rates of throughput. In fact, based on a price of 12.40 \$/B at Valdez (1976 \$'s) and risk multiplier of one, the after tax real rate of return on the investments in the field plus pipeline for Cases I, II, and III averages 14.2% and varies by less than  $\pm$  40 basis points between the Cases.

#### Effects of TAPS' Tariff

Some uncertainty surrounds the tariff determination, especially for the first few years of line operation. Moreover, the form of TAPS' ownership, i.e. undivided joint interest, allows each owner to post a separate tariff. Furthermore, an owner can either post an annual unsmoothed tariff or a smoothed tariff covering more than one year. Using Valdez as the pricing point for Prudhoe Bay crude circumvents the effects of uncertainty in tariff on the price of Prudhoe Bay crude to a West Coast refiner.

The effects of uncertainty in the tariff on the rate of return to the owners is small. Everything else being equal, a higher tariff results in higher state and federal income taxes on the pipeline operation and, simultaneously, lower well head price and hence lower royalty, severance tax, and state and federal corporate income taxes on field operations. In general, since the field's taxable income is more heavily taxed than the pipeline, one would expect a higher rate of return on the combined investment in the field and pipeline as a result of posting a higher tariff and shifting income from the field to the pipeline. However, actual computations indicate that such an increase in the rate of return is not significant.

### Effects of Crude Prices at Valdez on Rates of Return

The incremental effective tax rate which includes royalty, severance tax, state and federal corporate income tax is 62%. Thus, a price increase of 1 \$/B at Valdez results in a net after tax income to the owners of 38 ¢/B. An increase in price of 1 \$/B at Valdez results in a 1% increase in the after tax real rate of return. Similarly, a drop in price of 1 \$/B results in a decline of a little more than 1% in the after tax real rate of return. (See Figure VII-1.)

### Effects of Risk Multiplier

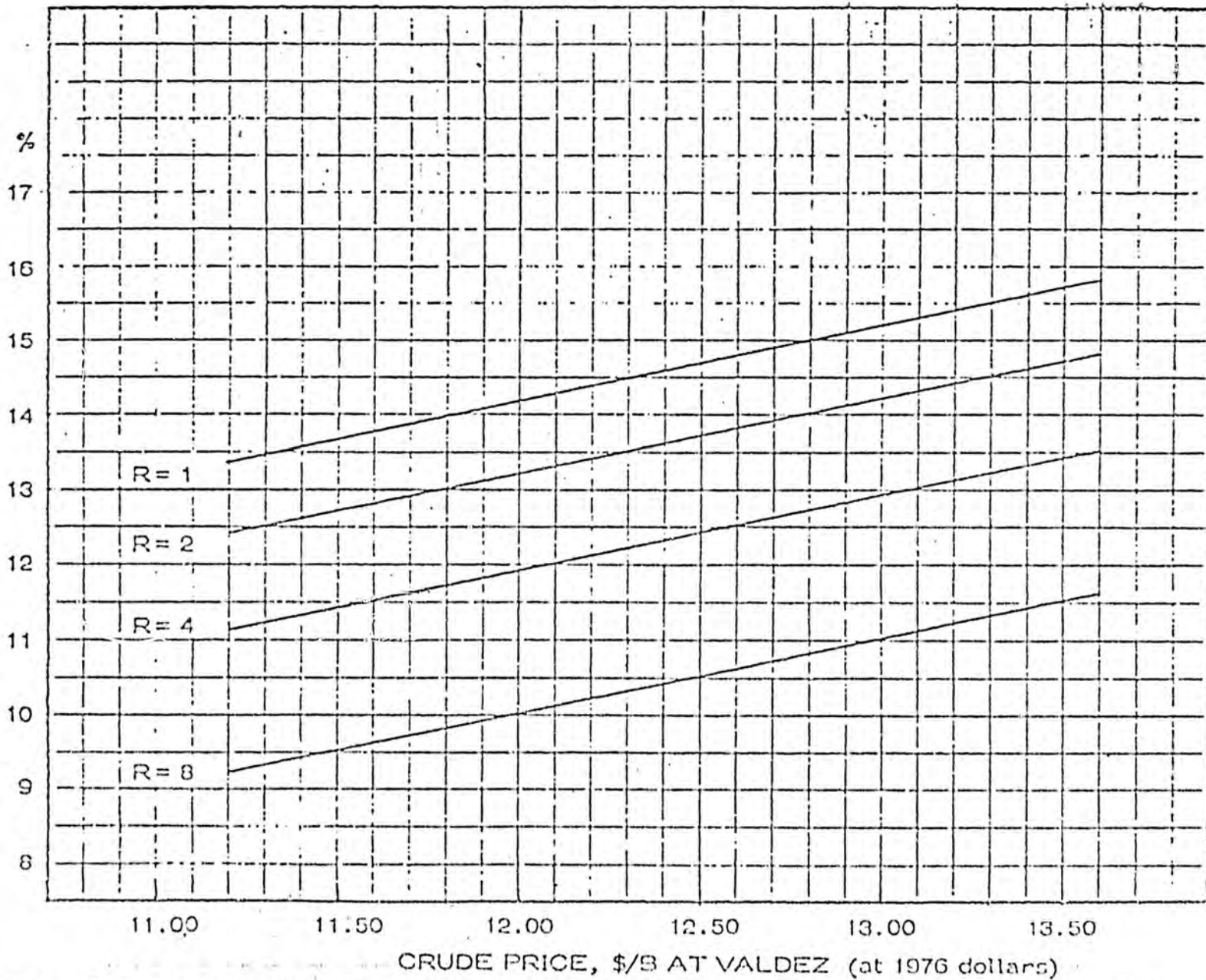
The risk concept as used in decisions involving exploratory activity expresses the geologist's subjective a priori judgment on the probability of success. When properly formulated, it should take the form of a frequency distribution function representing the probability of all possible outcomes. However, when applied after a discovery is made, it becomes an accounting procedure, such that successful exploratory ventures carry the costs of the unsuccessful ones. Since unsuccessful ventures can be expensed for federal income tax purposes, a risk multiplier "R" is defined such that  $R = 1 + .5(S - 1)$  where S is the inverse of the success ratio.

The risk multiplier thus defined has a significant effect on the rate of return. For the base case, i.e. Case I, applying a risk multiplier of 4 (i.e. a success ratio of 1 in 7) to industry's expenditures on the North Slope from 1959 to the discovery of Prudhoe Bay in 1968 reduces the after tax real rate of return on the investments in the field plus TAPS from 14.0% to 12.0%. A risk multiplier of 8 (success ratio of 1 in 15) reduces the rate

Figure VII-1

RELATIONSHIP BETWEEN  
RATES OF RETURN, RISK MULTIPLIER "R"  
AND CRUDE PRICES

DCF, REAL RATE OF RETURN ON INVESTMENT  
IN TAPS + FIELD



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of return to 18.4%.

A risk multiplier in the range of 3 to 4.5 is suggested.

- Industry's activity on the North Slope was preceded by an intensive exploration program carried out by the Navy on NPR #4 from 1944 to 1953 which contributed significantly to the geological knowledge of the North Slope.

The exploratory program of the early sixties may still yield new discoveries in the North Slope.

Hence, a crude price at Valdez in the range of 11.50 to 12.40 \$/B in 1976 dollars yields a DCF, after tax real rate of return of 12% on investments in TAPS plus the field.

#### Pricing Considerations in EPCA

Section 401, Part A of Title IV of Public Law 94-163, "Energy Policy and Conservation Act" (EPCA) stipulates that adjustments as production incentives can be made only on "... a finding by the President that such adjustment is likely to provide positive incentive for the discovery or development of high cost and high risk properties (including ... properties located north of the Arctic Circle...)". That section further provides that if the maximum average first sale price which has been adjusted to provide production incentives has the effect of reducing ceiling prices permitted for crude oil produced in the remainder of the U.S. to levels which result in less production of such crude oil, he may submit to the Congress an amendment to the regulations which:

"(a) excludes up to 2 million barrels per day of crude oil production transported through the trans-Alaskan pipeline from the computation of the maximum weighted average first sale price... and (b) established ceiling price... for the first sale of crude oil production (referred to in (a) above) such that the actual weighted average first sale price for such production will not exceed the highest actual weighted first sale price permitted under the regulations for significant volumes of any other classification of domestic crude oil."

In view of the above, certain pricing alternatives are suggested.

1. Pricing at Valdez

The benefits of a strategy based on crude pricing at Valdez are:

- a. It insulates the consumer in the lower 48 from the uncertainty in tariff determination.
- b. It provides a built-in incentive for the owners of Prudhoe Bay to develop the speculative and more expensive reserves in Prudhoe Bay Field, since the improved economy resulting from the increased rate of throughput in TAPS should contribute to offsetting the significantly higher costs of developing and operating the Kuparuk and Lisburne Oil Pools.

A regulation based on a weighted average sales price of 12.40 \$/B at Valdez equates the costs of Prudhoe Bay and Saudi Arabian crudes (exclusive of entitlements) to a West Coast refiner. A price at Valdez falling between 11.50 and 12.40 \$/B provides an equitable rate of return to the owners of Prudhoe Bay Field and TAPS.

2. Pricing at the Well Head

Under present tariff expectations, a well head price between 7.00 and 7.90 \$/B in 1976 dollars, to be adjusted quarterly for inflation, would be equivalent to a Valdez price of 11.50 to 12.40 \$/B.