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Oilfields and Crude Oil Characteristics

Cook Inlet Basin, Alaska

UNITED STATES DEPARTMENT OF THE INTERIOR

Report of Investigations 7688

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OILFIELDS AND CRUDE OIL CHARACTERISTICS

Cook Inlet Basin, Alaska

by

Donald P. Blasko,[1] Welton J. Wenger,[2] and J. C. Morris[3]

ABSTRACT

The first well that produced commercial quantities of oil in the Cook Inlet Basin of Alaska was completed in 1957. Since that time oil production in the basin has increased rapidly and by the end of 1969 had reached an annual rate of 74 million barrels. Five major oilfields had been developed, and two additional discoveries awaited development. Estimated amounts of recoverable oil by primary and secondary recovery methods total 2.7 billion barrels, or 36 percent of the estimated oil originally in place. Repressurization by injecting gas or water in formations containing undersaturated oil has significantly increased the volume of recoverable oil. All production has been from formations of the Tertiary age; that much of it is from depths of 10,000 feet or more is unusual for Tertiary formations. The oils are low in sulfur and contain low to moderate amounts of asphalt.

INTRODUCTION

The Cook Inlet Basin is in south-central Alaska. As shown in figure 1, it is bounded by the Alaska Range on the west, northwest, and north; the Talkeetna Mountains on the east; and the Barren Islands to the south, just south of the Chugach Islands. Anchorage, Alaska's largest city, lies within the basin area.

The climate of the Cook Inlet Basin is moderate; the region is warmed by the Japanese current, which provides warm, moist air in contrast to the cold, dry, arctic air of interior Alaska. Average July temperatures range from 68° F at Palmer in the north to 60° F at Homer in the south. January temperatures average 19° F at Palmer and 28° F at Homer. Precipitation is about 12 inches per year (11).[4]

The land area of the Cook Inlet Basin includes rugged glacial mountains that range in elevation up to 10,197 feet (Redoubt Volcano) on the west side

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[1]Petroleum engineer.
[2]Research chemist.
[3]Project leader.
[4]Underlined numbers in parentheses refer to items in the list of references preceding the appendix.

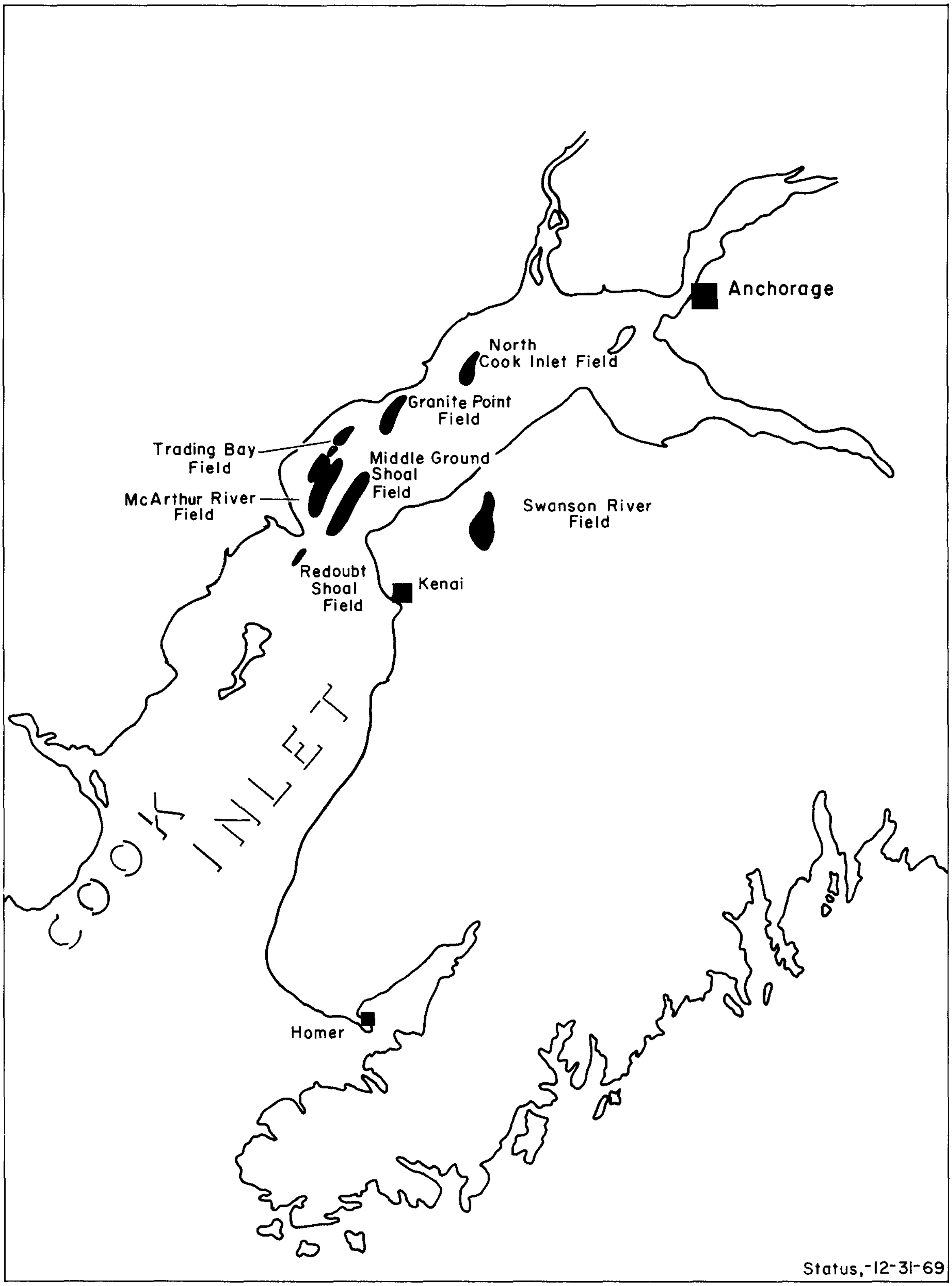


FIGURE 1. - Oilfields in the Cook Inlet Basin, Alaska.

of the inlet. Relatively flat, dry land suitable for farming lies in the northern Matanuska Valley. Low-lying swampy, muskeg-type land in the western half of the Kenai Peninsula is in contrast to the mountains in the eastern half of that peninsula. Permafrost is absent throughout the basin.

Cook inlet itself is a cold body of water characterized by 30-foot tides that ebb and flood at velocities up to 13 knots. From mid-November to April, the inlet is clogged with ice from its northern extremity at Anchorage south to the northern tip of Kalgin Island.

Early exploration for oil in Alaska, which started at the turn of the century, was not commercially productive although shows of oil-saturated formations were found in many instances. It was not until the late 1950's that exploration activities were undertaken on a major scale and techniques were developed to cope with weather extremes and with the ice floes and high tides that hampered early offshore operations.

Since the time of the discovery of oil on the Kenai Peninsula in 1957, the petroleum industry has had a great impact upon the development of the State of Alaska. Coinciding with the advent of statehood, the discovery of oil provided the impetus for a stable industry that has grown to be the most important mineral-producing industry in the State. This Bureau of Mines report gives details on the development of oil production in the Cook Inlet Basin and discusses the characteristics of the oils that are produced. The production data are arranged by fields in the chronological order of their discovery and development. The characteristics of 19 oils from the different fields are compared. Unabridged analysis reports of the oils are given in the appendix.

ACKNOWLEDGMENTS

The cooperation of the State of Alaska Department of Natural Resources, Division of Oil and Gas, in providing production figures, well locations, reservoir characteristics, and other general information is greatly appreciated. Individual oil companies supplied information and crude oil samples on which the analyses were made.

EARLY ALASKAN OIL EXPLORATION

The earliest attempts to find oil in Alaska took place in the Cook Inlet Basin. Oil seeps were noted on the west shore of the basin as early as 1853 (3, 7). During 1896, the Alaska Petroleum Co. was organized and began leasing land for future drilling. The first well drilled to find crude oil was spudded in 1900 near the south end of the Iniskin Peninsula near Bowser Creek (3) southwest of Chinitna Bay. Exact records are not available, but the well probably was drilled to about 1,000 feet. Oil shows were encountered, and the well was bottomed in the Tuxedni formation of Middle Jurassic age. The well was abandoned because of zones of salt water flowing under high pressure.

Three wells were drilled in the Oil Bay area, south of Chinitna Bay, between 1904 and 1906. All three were abandoned in Jurassic sediments. The deepest of the three, drilled to 900 feet, produced 10 barrels of oil per day (5). Difficulty with high-pressure water zones and sloughing formations was experienced with each well.

In the Dry Bay area of the Iniskin Peninsula, southwest of Chinitna Bay, two wells were drilled during the early 1900's by the Alaska Petroleum Co. (3). Both wells were abandoned at shallow depths owing to lost tools and equipment troubles. In 1921 the Anchorage Oil and Development Co. drilled an exploratory well east of Anchorage, and between 1926 and 1930 a firm known as Peterson Oil Association made an attempt to find production near Chickaloon just northeast of Palmer. These ventures were unsuccessful.

The earliest recorded deep-drilling exploration in the Cook Inlet Basin was in 1936. During that year, Havenstrite Oil spudded the Iniskin Bay Association No. 1 in the C sec 8, T 5 S, R 23 W (SM)[5] south of Chinitna Bay on the Iniskin Peninsula on the west shore of Cook Inlet. The drilling of that well progressed only during the late summer and fall, which was characteristic of early drilling in Alaska. It took 3 years to complete the well, which produced enough gas to run the powerplant. A high-gravity, low-sulfur, paraffin-base oil was encountered, but the apparent producing interval of 5,604 feet to 7,156 feet did not yield oil in commercial quantities. Total depth drilled was 8,775 feet.

Between 1940 and 1954, exploratory work in the Cook Inlet Basin, as in most of Alaska, was almost at a standstill. In the only Alaskan activity reported in this period, the U.S. Navy was carrying out extensive exploration to evaluate the possibilities of Naval Petroleum Reserve No. 4, in an area north of the Arctic Circle.

In 1954 Havenstrite Oil began drilling the Iniskin unit No. 1 in the same general area on the Iniskin Peninsula as that of the well drilled in 1936. Drilling was suspended in November 1959, and the well was finally plugged and abandoned in 1964. Total depth of the well was 9,476 feet, and the bit was reportedly drilling in Jurassic volcanics when the well was abandoned. Between 6,000 feet and 9,300 feet the formation was saturated with crude oil, but the lack of permeability prohibited production. This low permeability may be in part the result of swelling clays within the volcanics being drilled.

Another area of significant exploratory interest in the 1950's was in the northern upland regions of the Cook Inlet Basin southwest of the hamlet of Willow, near Houston. The Bureau of Mines, while drilling core holes for coal samples, encountered natural gas flows at around 450 feet (6). This quasi-discovery led to oil- and gas-leasing activity in the area and, ultimately, to the spudding of four wells between 1954 and 1959 by Anchorage Gas and Development, Inc. Although shows of natural gas were encountered, none of the wells was commercially productive. The Rosetta No. 3, drilled to a total depth of 6,109 feet, was the deepest of the four; the others reached

[5]Seward Meridian.

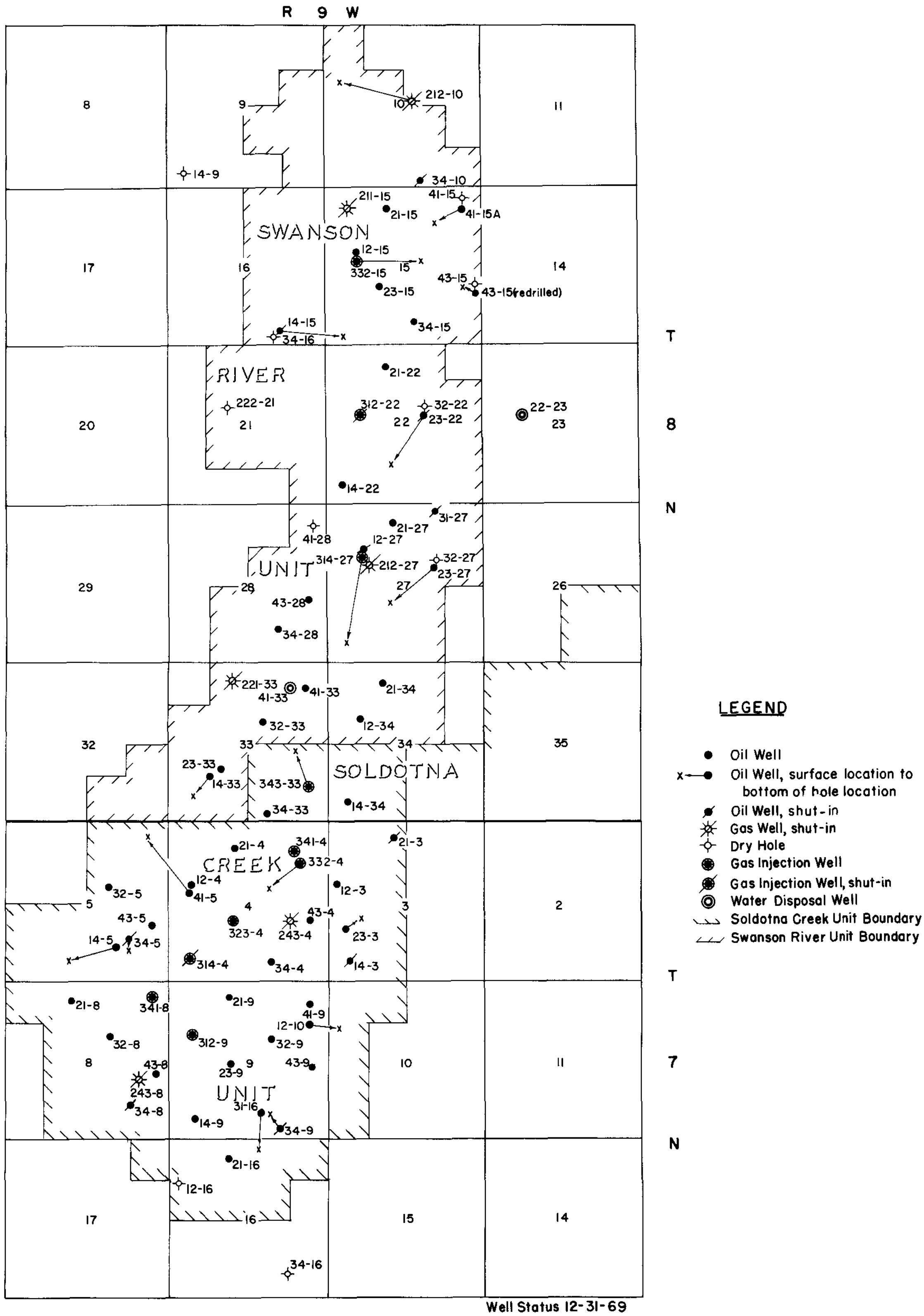


FIGURE 2. - Swanson River Unit–Soldotna Creek Unit (Swanson River Field).

approximately 1,500 feet. Since that time, there have been several dry holes drilled on the west side of the Knik Arm.

The modern oil boom in Alaska began in 1957 when Richfield Oil Corp. drilled the discovery well in what is now the Swanson River field.

SWANSON RIVER FIELD

The Swanson River field lies north and west of Kenai and consists of two units, the Swanson River unit and the Soldotna Creek unit (fig. 2). Standard Oil Co. of California operates the field for itself and for Atlantic Richfield Co., Union Oil Co. of California, and Marathon Oil Co. Production data for crude oil, natural gas, and water are included in table 1, and reservoir data are given in table 2.

The discovery well, a joint venture of Richfield Oil Co. and Standard Oil Co. of California, was drilled by Richfield on the Kenai Peninsula about 14 miles north of Soldotna. The well was drilled on federally owned land in the Kenai National Moose Range; the land had been unitized for drilling purposes in 1956. The well produced 900 barrels of oil per day from the Hemlock formation of Tertiary age.

Land to the south of the Swanson River unit, also on the Kenai National Moose Range, was unitized effective December 1959 as the Soldotna Creek unit. A well was spudded within the newly formed unit during the same month, and the Soldotna Creek unit No. 1 (No. 14-4) was completed as a wildcat discovery in March 1960. Oil was produced from the Hemlock formation.

The Swanson River unit No. 10 (No. 212-10), completed during 1960, was the first dry-gas well in the Swanson River unit. Production was from shallow sands of Tertiary age in the Sterling formation.

Development drilling in the Swanson River unit to the end of 1963 resulted in 26 oil producers, four dry-gas producers, nine dry holes, and one water-disposal well. Development drilling in the Soldotna Creek unit resulted in 33 oil wells, two dry-gas wells, and four dry holes. There was no further development drilling in the Swanson River field until mid-1969. During 1969, two wells were completed as oil producers in the Soldotna Creek unit, and a third was spudded.

Recoverable oil reserves in the field have been significantly increased by gas repressurization. The original producing mechanism of the Hemlock formation in the Swanson River field was reservoir fluid expansion. At the onset of production, little water was produced with the oil, and this was only from wells on the edge of the reservoir. The oil under normal reservoir conditions was undersaturated; gas-oil ratios averaged about 180 to 1. The reservoir characteristics (table 2) indicated that the reservoir would be susceptible to gas repressurization.

TABLE 1. - Production and injection--fields in Cook Inlet Basin, Alaska

Year	Field or unit	Oil, bbl	Cumulative oil, bbl	Associated gas, Mcf	Associated water, bbl	Average number of oil wells		Gas injected, Mcf	Water injected, bbl
						Producing	Shut in		
1958	Swanson River unit	35,754	35,754	5,612	283	2	0	0	0
1959	Swanson River unit	136,590	222,344	27,145	33,431	5	0	0	0
1960	Swanson River unit	298,548	520,892	42,072	8,755	3	4	0	0
	Soldotna Creek unit	259,451	259,451	56,568	2,708	3	3	0	0
	Total	557,999	780,343	98,640	11,463	6	7	0	0
1961	Swanson River unit	1,986,377	2,507,269	333,861	114,108	18	1	0	0
	Soldotna Creek unit	4,340,124	4,599,575	952,373	44,307	23	1	0	0
	Total	6,326,501	7,106,844	1,286,234	158,415	41	2	0	0
1962	Swanson River unit	2,895,398	5,402,667	496,474	214,550	21	4	0	0
	Soldotna Creek unit	7,363,712	11,963,287	1,407,182	79,583	29	0	257,211	0
	Total	10,259,110	17,365,954	1,903,656	294,133	50	4	257,211	0
1963	Swanson River unit	2,937,445	8,340,112	486,866	287,075	24	2	0	0
	Soldotna Creek unit	7,802,519	19,765,806	2,305,895	171,706	29	0	6,442,632	0
	Total	10,739,964	28,105,918	2,792,761	458,781	53	2	6,442,632	0
1964	Swanson River unit	3,213,542	11,553,654	740,219	669,068	25	1	0	0
	Soldotna Creek unit	7,840,330	27,606,136	2,476,457	584,091	29	1	5,589,452	0
	Total	11,053,872	39,159,790	3,215,676	1,253,159	54	2	5,589,452	0
1965	Swanson River unit	3,207,349	14,761,003	775,132	1,120,472	25	1	0	0
	Soldotna Creek unit	7,892,055	35,498,191	3,035,504	562,066	29	1	4,817,006	0
	Middle Ground Shoal field	27,181	27,171	10,349	862	3	0	0	0
	Total	11,126,575	50,286,365	3,820,985	1,683,400	57	2	4,817,006	0
1966	Swanson River unit	3,323,099	18,084,102	1,207,363	1,213,299	20	3	9,244,998	0
	Soldotna Creek unit	8,388,645	43,886,836	4,384,595	854,409	27	1	19,368,369	0
	Middle Ground Shoal field	2,646,469	2,673,640	1,191,879	32,738	9	1	0	0
	Total	14,358,213	64,644,578	6,783,837	2,100,446	56	5	28,613,367	0
1967	Swanson River unit	4,114,474	22,198,576	5,967,570	1,508,432	16	7	11,450,236	52,000
	Soldotna Creek unit	8,866,008	52,752,844	7,499,918	749,481	20	8	29,243,506	114,644
	Middle Ground Shoal field	7,408,090	10,081,730	3,197,341	141,345	17	1	0	0
	McArthur River field	748,815	748,815	218,721	771	2	0	0	0
	Trading Bay field	726,994	726,994	668,863	777	8	0	0	0
	Granite Point field	7,053,064	7,053,064	4,810,651	220,119	11	0	0	0
	Total	28,917,445	93,562,023	22,363,064	2,620,925	74	16	40,693,742	166,644
1968	Swanson River unit	3,119,677	25,318,253	7,307,467	965,779	13	10	6,154,783	0
	Soldotna Creek unit	10,499,781	63,252,625	17,988,727	1,219,643	23	3	51,727,930	0
	Middle Ground Shoal field	11,110,097	21,191,827	7,443,540	482,007	37	2	0	555,488
	McArthur River field	21,782,310	22,531,125	6,090,659	272,176	23	0	0	0
	Trading Bay field	3,477,175	4,204,169	2,774,845	40,664	21	4	0	0
	Granite Point field	13,131,377	20,146,952	9,962,768	168,398	31	2	0	93,597
	South Middle Ground Shoal unit	3,026,884	3,026,884	910,612	100,650	10	0	0	0
	Total	66,147,301	159,671,835	52,478,618	3,249,317	158	21	57,882,713	649,085
1969	Swanson River unit	3,188,044	28,506,297	12,715,953	1,262,477	16	7	15,018,015	0
	Soldotna Creek unit	9,962,833	73,215,458	27,766,188	1,250,133	23	3	56,704,860	0
	Middle Ground Shoal field	8,470,311	29,662,138	6,790,988	347,398	34	5	0	5,458,699
	McArthur River field	31,300,978	53,832,103	10,540,561	529,271	38	12	0	9,656,610
	Trading Bay field	9,933,818	14,137,987	6,738,493	263,662	30	7	0	0
	Granite Point field	9,183,291	29,330,243	8,240,965	250,793	36	3	0	41,855
	South Middle Ground Shoal unit	1,996,779	5,023,663	625,717	142,324	10	0	0	38,764
	Total	74,036,054	233,707,889	73,408,865	4,046,058	187	37	71,722,875	15,195,928

TABLE 2. - Reservoir data, Swanson River field, Hemlock formation

Initial reservoir pressure............psi..	5,650
Saturation pressure...................psi..	1,000-1,400
Gravity............................° API..	29.7-36
Reservoir temperature.................° F..	180
Net pay thickness......................ft..	8-300
Porosity..............................pct..	18-26
Permeability...........................md..	0-3,275
Connate water.........................pct..	40
Formation volume factor....................	1.12
Original gas-oil ratio............scf/STB..	105-550

The gas repressurization program of the Hemlock formation in the Soldotna Creek unit began in November 1962. Produced gas was gathered from wells in both the Soldotna Creek unit and the Swanson River unit and was injected through one injection well in the Soldotna Creek unit. By the end of the year, another injection well had been added, and a total of 252,160 Mcf of gas had been injected. Another injection well was added in March 1963.

In 1965 Standard Oil Co. of California began expanding the reservoir repressurization program in the field. In May 1966, gas was injected in the Swanson River unit for the first time, using three injection wells. By early 1966, increased volumes of gas were being injected in the Soldotna Creek unit. Average daily injection rates increased from 12,000 Mcf in 1965 to 89,000 Mcf in 1966 to 192,592 Mcf in December of 1969.

Owing to production problems, the six shallow dry-gas wells in the Swanson River field were shut in, which made it necessary to obtain injection gas from the Kenai unit gasfield 20 miles to the south. Under terms of an agreement with Union Oil Co., operator of the Kenai unit, the gas that is obtained from the Kenai unit and injected in the Swanson River field will be reclaimed by Union Oil when the reservoir is depleted of oil.

At the end of December 1969, the two units combined had 41 wells producing oil, and 10 wells were shut in. Ten wells had been converted to gas-injection wells, and gas was being injected through eight of them. One dry hole was being used for produced water disposal, and a well drilled for water disposal was being used to inject produced water into nonproductive formations at about 3,000 feet.

Using reservoir data as the basis of determination, it has been estimated that the amount of oil originally in place in the Swanson River field was 1.6 billion barrels. Of the original oil in place, it is estimated that a total of 647 million barrels, about 40 percent, is recoverable by both primary and secondary means. Cumulative production to the end of 1969 was nearly 102 million barrels, or 6 percent of the original oil in place and 15 percent of the estimated recoverable oil.

The producing operations in the field are fully automated, and metering devices are housed in enclosures. The crude oil moves from the field via an 8-inch diameter, 22-mile-long pipeline to a small refinery and tanker terminal at Nikiski. Standard Oil Co. of California's 20,000 barrel-per-day refinery makes jet fuel, heating fuel, and diesel oil; the residuum goes to west coast refineries for further processing. Oil that is shipped from the tanker terminal also goes to west coast refineries.

MIDDLE GROUND SHOAL FIELD

The Middle Ground Shoal field (fig. 3) is about 4 miles west of East Foreland in offshore Cook Inlet waters on State-leased lands. Included in the field is the South Middle Ground Shoal unit, which is operated by Shell Oil Co. for itself and its partners, Atlantic Richfield Co. and Standard Oil Co. of California. The remainder (northern portion) of the field is operated by Amoco Production Co. whose partners are Skelly Oil, Phillips Petroleum, and Atlantic Richfield Co. Data on the production of crude oil, natural gas, and water are included in table 1; reservoir characteristics are given in tables 3 and 4.

TABLE 3. - Reservoir data, Middle Ground Shoal field, Hemlock formation

Initial reservoir pressure..................psi..	3,655
Saturation pressure.........................psi..	1,500
Gravity..................................° API..	36-38
Reservoir temperature......................° F..	155
Net pay thickness............................ft..	500
Porosity....................................pct..	11
Permeability.................................md..	10
Estimated connate water.....................pct..	40
Estimated formation volume factor................	1.12
Original gas-oil ratio.................scf/STB..	430

TABLE 4. - Reservoir data, Middle Ground Shoal field, Tyonek formation (Middle Ground Shoal member)

Initial reservoir pressure................................psi..	2,210
Saturation pressure.......................................psi..	1,900
Gravity..° API..	36-38
Reservoir temperature....................................° F .	125
Net pay thickness..ft..	300
Porosity..pct..	16
Permeability...md..	100
Estimated connate water...................................pct..	45
Estimated formation volume factor..............................	1.12
Original gas-oil ratio...............................scf/STB..	400

The discovery of the Middle Ground Shoal field was made by Amoco Production Co. The company spudded the Middle Ground Shoal-State 17595 No. 1 during May 1962. The well blew out under high-pressure gas twice, and after

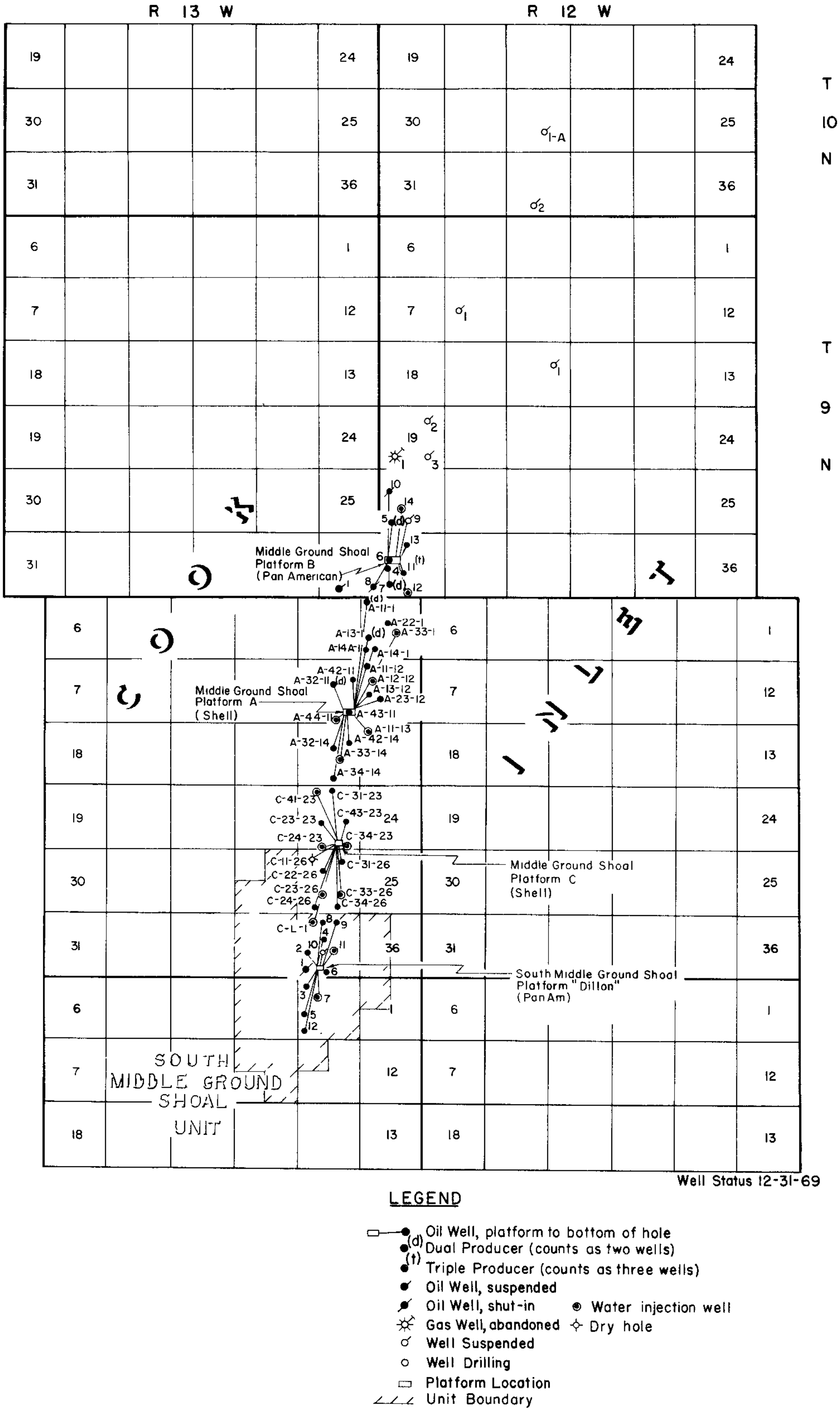


FIGURE 3. - Middle Ground Shoal Field.

being controlled the second time, was plugged and abandoned. Amoco then spudded Middle Ground Shoal-State 17595 No. 2 in May 1963 but suspended operations late in 1963. Shell Oil Co. spudded the S.R.S. (Shell, Richfield, Standard) Middle Ground Shoal-State No. 1 late in 1963. Ice floes in the Cook Inlet forced suspension of the operations for the winter, and the well was reentered in the spring. The well was tested in the Hemlock conglomerate during September 1964 and produced 650 barrels of oil per day.

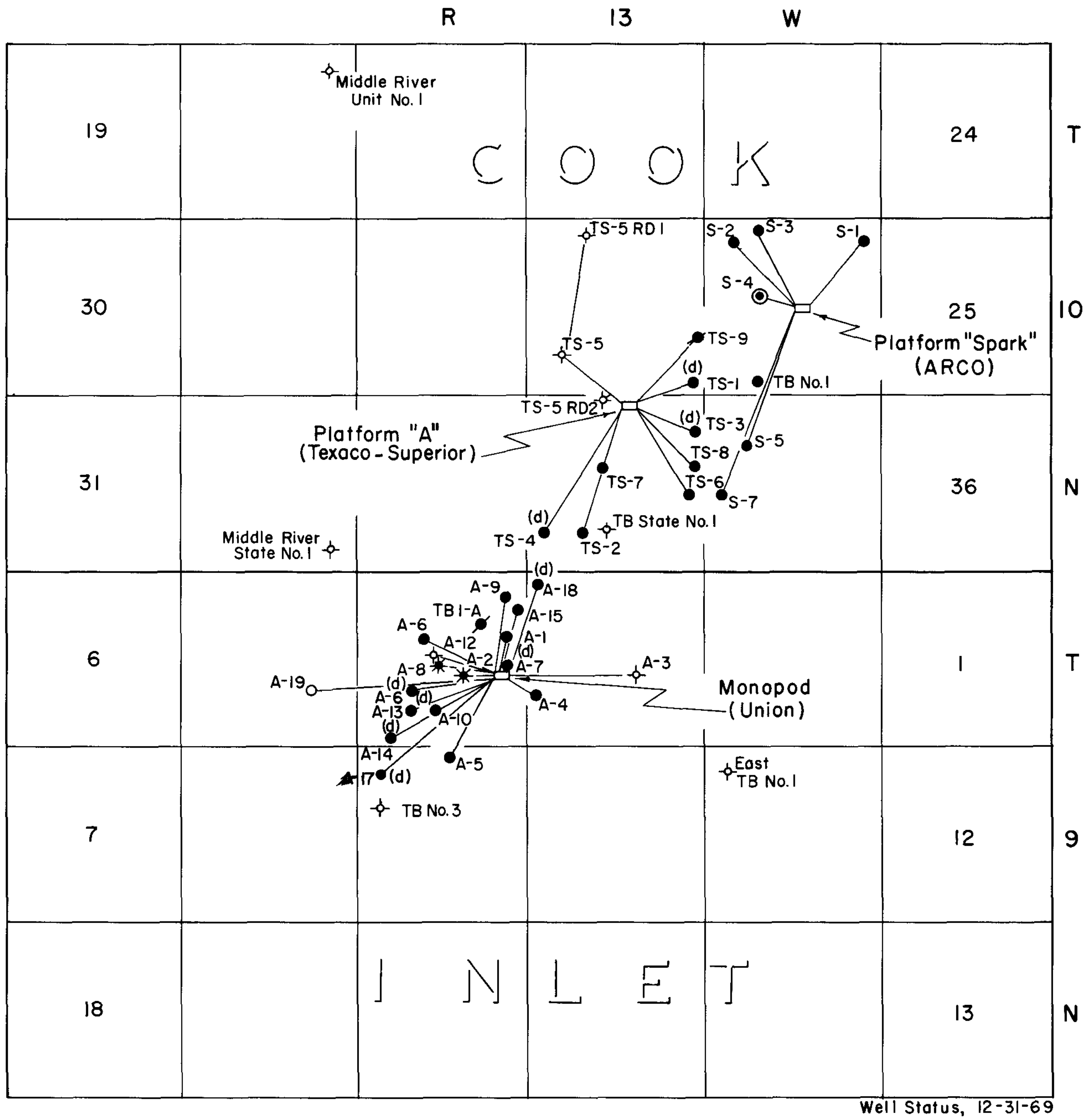
During 1964, Amoco Production brought in Middle Ground Shoal-State 17595 No. 4 for 5,000 barrels of oil per day. Production was from five different sands in the Tyonek and Hemlock formations of Tertiary age. This well confirmed the potential of the Middle Ground Shoal structure.

Amoco Production Co. and Shell Oil Co. then constructed the first permanent drilling and development platforms in offshore Cook Inlet. By the end of 1965, Shell had completed three wells on platform A and began transmitting oil to shore facilities via a dual 8-inch pipeline. During April 1966, Amoco began production from its platform Baker and transmitted oil via the 8-inch line to shore facilities on East Foreland. The 8-inch pipeline is commonly owned by both Shell and Amoco. Shell Oil Co. added another development platform in the Middle Ground Shoal field (platform C) during 1967). From the beginning of development drilling in 1965 to the end of 1969, Shell had drilled a total of 32 wells from the two platforms, resulting in 30 oil wells, one dry hole, and one water-injection well.

Amoco completed an oil well nearly 4 miles south of what was then the known producing limits of the Middle Ground Shoal field in 1965. Subsequent drilling indicated that the new producing area was not a new field discovery but a southern extension of the Middle Ground Shoal field. This area was unitized in 1967 and became the South Middle Ground Shoal unit. Amoco erected another platform (Dillon) for development of the unit. Toward the end of 1969, 11 wells had been drilled from platform Dillon, which resulted in 10 oil wells, with operations suspended in one well. All producing wells are completed in the Hemlock formation at South Middle Ground Shoal. Oil moves to the East Foreland receiving facility via Amoco's dual 8-inch pipeline.

On platform Baker, 13 wells have been drilled including a recompletion of Middle Ground Shoal-State 17595 No. 4, a well which had been drilled from a temporary platform. Of the remaining 12 wells, 10 were oil wells, one was a water supply well, and operations were suspended in one well. Five of the 12 oil wells are dual completion wells, and one is a triple completion well.

Water is being injected for pressure maintenance in both the Tyonek and Hemlock formations of Tertiary age in the Middle Ground Shoal field. Both reservoirs are undersaturated and have undergone a rapid reservoir pressure decline. Reservoir characteristics (tables 3-4) indicated that the formations would be susceptible to water injection as a form of pressure maintenance. During August 1968, Shell Oil Co. began a pilot water-injection program through one well on its platform A. In February 1969 the program was advanced to full-scale status, and injection in three wells began on platform A. By the end of the year, water was being injected into wells on platform C also.



LEGEND

- Oil Well, platform to bottom of hole
- (d) Dual Producer (counts as two wells)
- Oil Well, shut-in
- Oil and Gas Well
- Well, drilling
- Dry Hole
- Water Injection Well
- Platform Location

FIGURE 4. - Trading Bay Field.

At the end of 1969, Shell was producing oil from 20 wells on platforms A and C. Five wells on platform A and six wells on platform C had been converted to water-injection wells, and injection rates averaged 33,626 barrels of water per day during December 1969. Water for injection was being obtained from Cook Inlet and treated and filtered before injection.

Amoco also has undertaken plans for a pressure-maintenance program with water injection at its two platforms. In December 1969 the injection program was started with the injection of 429,656 barrels of water into four wells.

At the end of 1969, Amoco's platform Baker had six wells producing oil and two wells shut in. Two wells were being used for water injection. On platform Dillon, eight wells were producing oil, and two wells were being used for water injection.

Based upon reservoir characteristics, estimates of oil originally in place in both producing zones in the Tertiary reservoir total 1,239 million barrels. It is estimated that 20 percent of the oil will be recovered by primary means and that 10 percent will be recovered by secondary operations for a total recovery of 372 million barrels of oil. Cumulative production to the end of 1969 was 35 million barrels, or 9 percent of the recoverable oil.

TRADING BAY FIELD

The Trading Bay field (fig. 4) is in offshore Cook Inlet, 4-1/2 miles northwest of the Middle Ground Shoal field. Production data on the field are included in table 1; reservoir characteristics are given in tables 5 and 6.

TABLE 5. - Reservoir data, Trading Bay field, Hemlock formation

Initial reservoir pressure........................psi..	2,745
Saturation pressure...............................psi..	1,622
Gravity...° API..	31
Reservoir temperature.............................° F..	136
Net pay thickness..................................ft..	300
Porosity..pct..	14.6
Permeability.......................................md..	10
Connate water.....................................pct..	40
Estimated formation volume factor.....................	1.17
Original gas-oil ratio.........................scf/STB..	318

TABLE 6. - Reservoir data, Trading Bay field, Tyonek formation (Middle Ground Shoal member)

Initial reservoir pressure........................psi..	2,613
Saturation pressure...............................psi..	1,921
Gravity...° API..	25.6
Reservoir temperature.............................° F..	112
Net pay thickness..................................ft..	1,000
Porosity..pct..	25
Permeability.......................................md..	250
Connate water.....................................pct..	45
Estimated formation volume factor.....................	1.11
Original gas-oil ratio.........................scf/STB..	268

The discovery of the Trading Bay field was made by Union Oil Co. of California in June 1965. The wildcat well, a joint venture between Union Oil and Marathon Oil Co., discovered oil in commercial quantities in the Upper Hemlock formation of Tertiary age. In 1966, while Union Oil Co. was constructing a permanent drilling and production platform (Monopod) on the Trading Bay structure, Texaco Inc. completed a successful oil well to further define the field. Atlantic Richfield Co. also completed a well in the field in 1967. On the basis of these successful wells, platforms have been erected by Texaco and its partner, Superior Oil Co., and by Atlantic Richfield. Production from Union's Monopod began in January 1967. Texaco-Superior began production from their platform (platform A) in September 1968. Atlantic Richfield's platform (Spark) was completed and production begun in 1969.

Drilling from Union Oil Co. of California's Monopod by the end of 1969 resulted in 16 oil wells and one dry hole. Seven oil wells were completed in the Tyonek formation, two in the Hemlock formation, five in both the Tyonek and Hemlock formations, and two dual completions to produce gas from the Tyonek formation and oil from the Hemlock formation. Status of the wells on the Monopod at the end of 1969 was as follows: Ten Tyonek formation wells producing and two shut in, seven Hemlock formation wells producing and two shut in, and both Tyonek dry-gas wells producing. (Well status on figure 4 will not reflect true status because of dually completed wells having different conditions of status.)

By the end of 1969, Texaco Inc. had completed a nine-well development program on the Texaco-Superior platform A. One well was completed in each of the Tyonek and Hemlock formations, and six wells were completed capable of producing oil from both the Tyonek and Hemlock formations. At the end of 1969, there were seven wells producing oil and one well shut in.

Atlantic Richfield completed five wells to produce from both the Tyonek and Hemlock formations on the platform Spark. All five of these wells were producing at the end of 1969. In addition, two dry holes and one water-injection well were drilled.

As is common in the fields in the Cook Inlet Basin, the Tertiary reservoir is undersaturated, and pressure maintenance will be necessary for optimum oil recovery. Plans were being made at the end of 1969 to initiate secondary recovery by water injection.

Based upon reservoir characteristics (tables 4-5), the following estimates have been made: (1) In the Tyonek formation, original oil in place approximates 1,345 million barrels, and total recovery is expected to be approximately 40 percent, or 538 million barrels; (2) the original oil in place in the Hemlock reservoir is estimated to be 209 million barrels, and total recovery will be about 40 percent or 84 million barrels; and (3) total recovery from both producing reservoirs in the Trading Bay field will be about 622 million barrels of oil.

Oil from the Trading Bay field is transmitted from the platforms through dual 8-inch lines that run to treating facilities on the west shore of Cook Inlet. Oil is then transmitted south to tanker loading facilities at Drift River via the 20-inch Drift River pipeline.

McARTHUR RIVER FIELD

The McArthur River field (fig. 5) is located in offshore Cook Inlet near the west shore of East Foreland. Production data on the field are included in table 1.

The rapid development of the McArthur River field from late 1965 through 1966 often led to confusing nomenclature in the field. The discovery well, completed by Union Oil Co. of California in November 1965, was designated Grayling No. 1-A. This well together with others being drilled in the area was first referred to as the Grayling field. In 1966, Union Oil Co. of California completed the Kustatan State No. 1-A, which was thought to be the discovery well of another field, the Dolly Varden. Also in 1966, Amoco Production Co. completed the North Redoubt State No. 1, and Atlantic Richfield completed the McArthur State No. 1. Eventually, it was learned that all these wells were on the same structure, and they were combined into what is now the McArthur River field.

Other confusing nomenclature arose when the McArthur River field was unitized in 1967. At that time it was thought that the Trading Bay field was part of the structure being unitized, so the unit was called the Trading Bay Unit, with Union Oil Co. of California as the operator. Later drilling determined that the Trading Bay field was on a separate structure, so that field was not included in the Trading Bay unit, although the name remained.

Union Oil Co. completed construction of its permanent drilling and production platform (Grayling) in 1967 near the location of their Grayling No. 1 discovery well; the first production from the platform and the field, recorded during October of 1967, was from the Hemlock formation. Development drilling continued, and in August 1968, Union announced that oil had been encountered below the Hemlock formation in the Tertiary West Foreland formation. Production is also obtained from the shallower Tyonek formation (mid-Kenai). At the end of 1969 on the Grayling platform, there were 12 wells producing oil from the Hemlock formation and two wells shut in, three wells producing from the West Foreland and Tyonek formations, four wells injecting water in the Hemlock, and one well producing gas from the Tyonek formation.

The Atlantic Richfield Co., as suboperator of the Trading Bay unit, erected the King Salmon platform during 1967, and production began early in 1968. The platform is located near its McArthur State No. 1 well. At the end of 1969, there were eight wells producing oil from the Hemlock, two wells shut in, one well producing gas from the Tyonek formation, and four wells injecting water into the Hemlock formation.

Marathon Oil Co., an operating partner of Union Oil Co. of California in Trading Bay unit and a suboperator of the unit, erected the Dolly Varden

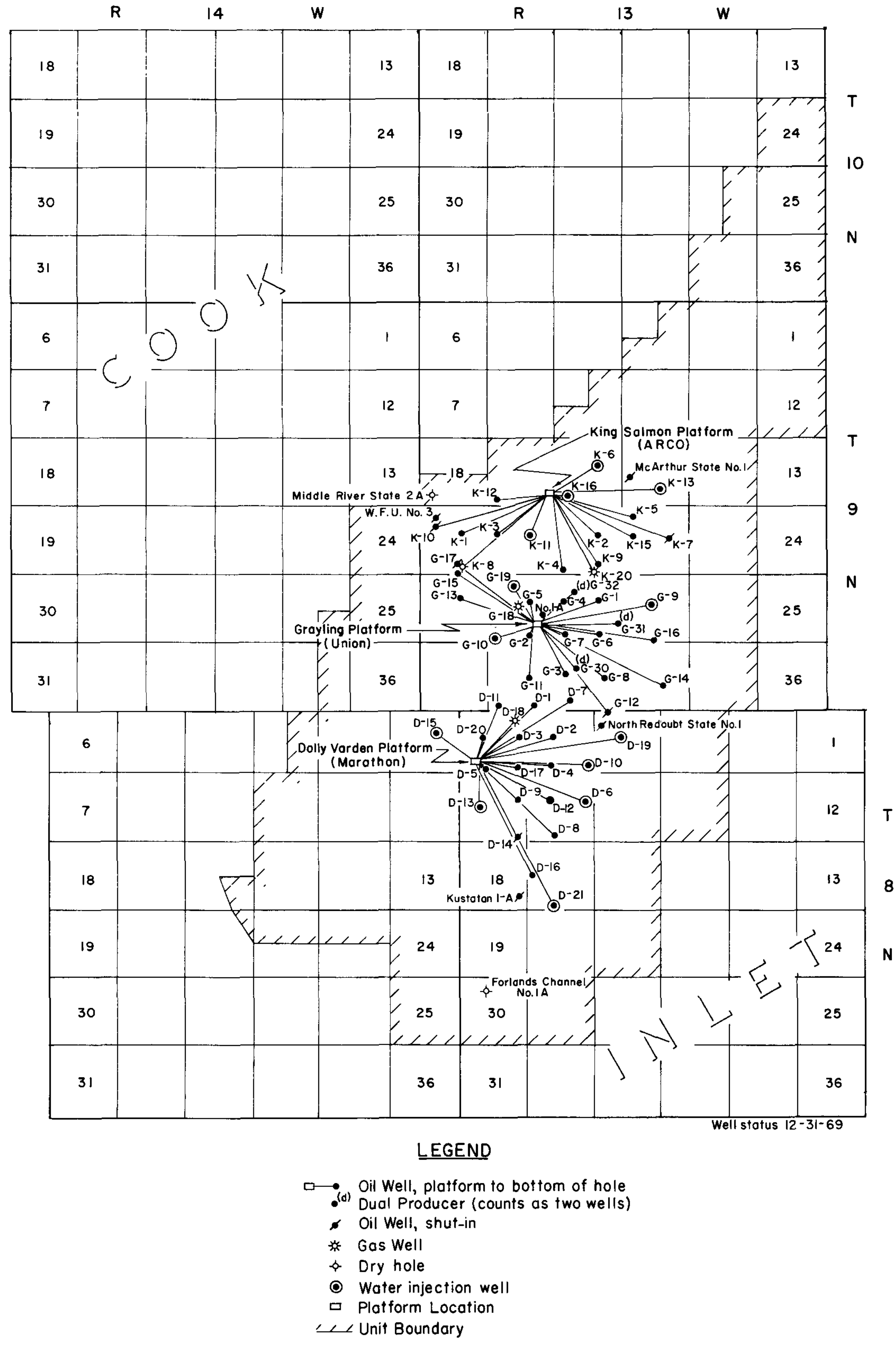


FIGURE 5. - McArthur River Field (Trading Bay Unit).

platform during 1967 and began drilling and production operations during 1968. At the end of 1969, there were 13 wells producing oil from the Hemlock formation, one well shut in, one well producing gas from the Tyonek formation, and six wells injecting water into the Hemlock formation.

Based upon reservoir characteristics (table 7) the amount of oil originally in place is estimated to be 1,820 million barrels. Recovery of the original oil in place by normal pressure depletion is estimated at 18 percent. Because the Hemlock formation is undersaturated, pressure maintenance by water injection could probably recover an additional 17 to 20 percent of the oil. Thus, it is estimated that a total of 35 percent of the original oil in place, or 637 million barrels of oil, could be recovered.

TABLE 7. - Reservoir data, McArthur River field (Trading Bay unit) Hemlock formation

Initial reservoir pressure...psi..	4,250
Saturation pressure...psi..	1,782
Gravity...° API..	35
Reservoir temperature...° F..	180
Net pay thickness...ft..	500
Porosity...pct..	10.5
Permeability...md..	53
Connate water...pct..	35
Formation volume factor...	1.21
Original gas-oil ratio...scf/STB..	312

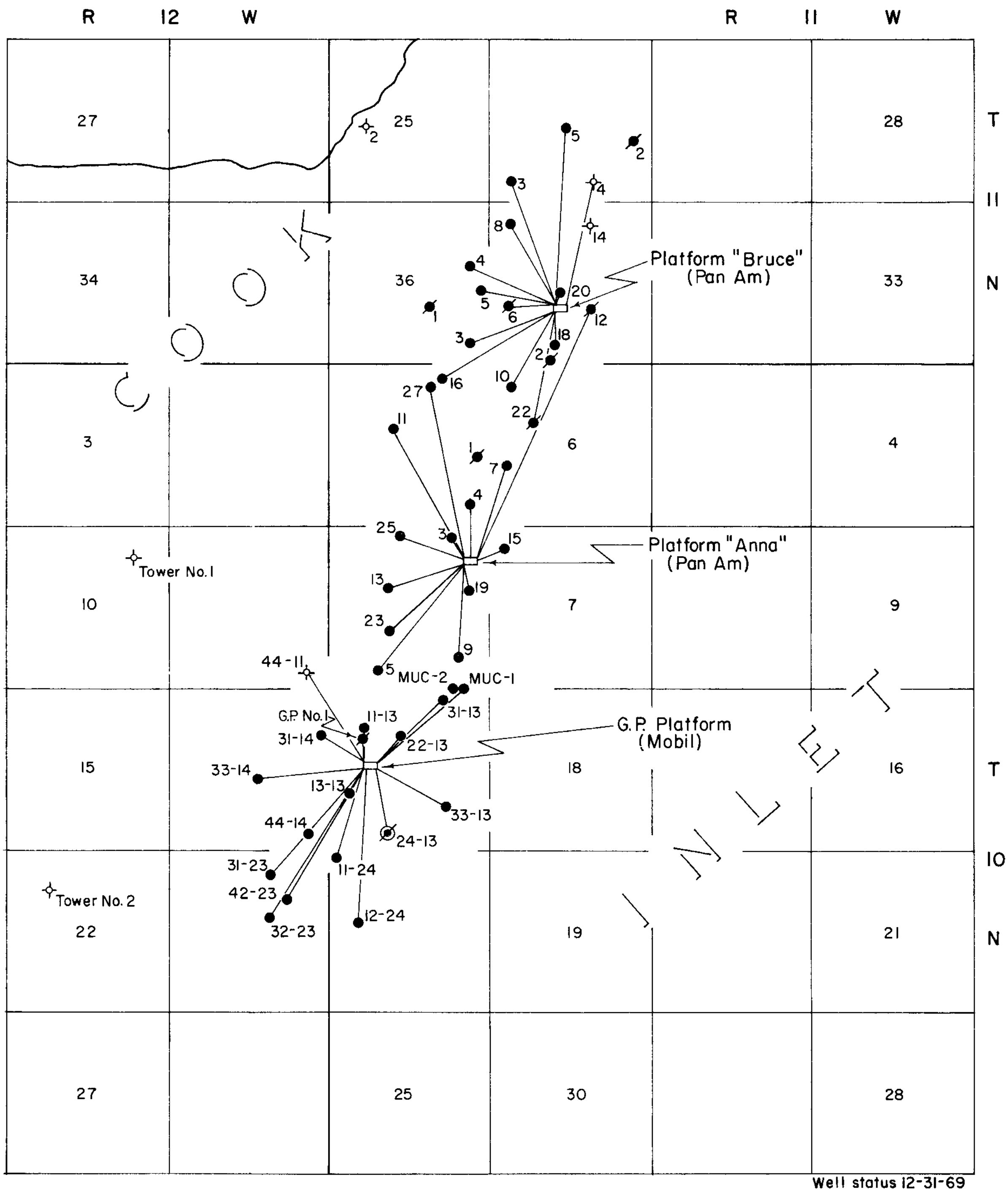
Oil from the McArthur River field reaches facilities on the west shore via pipeline. The Dolly Varden and King Salmon platforms have twinned 8-inch lines. The line from the Grayling platform is a twinned 10-inch line. After the oil is treated at the onshore facility, it enters the Drift River pipeline and is transmitted to the Drift River tanker terminal.

GRANITE POINT FIELD

The Granite Point field (fig. 6), the northernmost field in offshore Cook Inlet, is located near the west shore of the inlet about 15 miles north of the East Foreland. Production data are included in table 1.

The Granite Point field was discovered by Mobil Oil Co. in May 1965 while drilling for itself and its lease partner, Union Oil Co. of California. Amoco Production Co. completed an offset well about 1-1/2 miles northeast of the Mobil discovery that produced over 2,400 barrels of oil per day. Production was from the Tertiary Tyonek formation. Amoco drilled a number of expendable wells from a temporary platform before determining the best location for its permanent platform.

Amoco Production constructed two platforms on the Granite Point structure during 1966. Both platforms were placed near the sites of previously drilled holes. Both of Amoco's platforms (Anna and Bruce) are north and east of Mobil's platform. Amoco began producing oil from Granite Point during March 1967.



LEGEND

- Oil Well, platform to bottom of hole
- Oil Well, shut-in
- Dry hole
- Water injection well, shut-in
- Platform Location

FIGURE 6. - Granite Point Field.

During 1966, Mobil constructed a permanent drilling and production platform just south of their original discovery. Production from Mobil's platform began in May 1967.

Oil in the Middle Ground Shoal member of the Tyonek formation is undersaturated with gas, as in other fields in the Cook Inlet Basin. Pressure maintenance by water injection began on a limited scale in August 1968 on Mobil's platform. Water was injected intermittently through one well until mid-1969 when injection ceased. During the year, two wells were drilled through which water will be injected in the future.

At the end of 1969 there were 15 wells producing oil on Mobil's platform, two of which are to be used for water injection; one water-injection well was shut in.

Amoco had 12 wells producing oil and one well shut in on platform Anna. There were 10 wells producing and one well shut in on platform Bruce at the end of 1969.

Based upon available reservoir data (table 8), it has been estimated that there were 1,592 million barrels of oil originally in place in the Granite Point field and that 15 percent would be recovered by primary means. Secondary recovery operations by water injection for pressure maintenance are expected to recover an additional 15 percent of the oil, which would give a total recovery of 30 percent.

TABLE 8. - Reservoir data, Granite Point field, Tyonek formation (Middle Ground Shoal member)

Initial reservoir pressure....................psi..	4,116
Saturation pressure....................psi..	2,400
Gravity....................° API..	41-44
Reservoir temperature....................° F..	170
Net pay thickness....................ft..	600
Porosity....................pct..	14
Permeability....................md..	10
Estimated connate water....................pct..	30
Estimated formation volume factor....................	1.1
Original gas-oil ratio....................scf/STB..	960

Oil from Mobil's platform moves through twinned 8-inch pipelines to shore facilities on the west side of Cook Inlet. There the oil enters the 20-inch Drift River pipeline and moves to the terminus at the mouth of the Drift River, south of the Forelands. From there the oil is transported by tankers to west coast refineries in the "lower 48."

Oil from Amoco's two platforms is piped through two 15-mile long, 10-inch-diameter pipelines running south from the Granite Point field to facilities on the East Foreland. The pipeline is under Cook Inlet for its entire length. The oil is then piped from receiving facilities at East Foreland to the Kenai pipeline tanker loading dock at Nikiski for tanker shipment to west coast refineries.

UNDEVELOPED AREAS

Two additional areas of offshore Cook Inlet have shown oil-producing capabilities. A short description of each follows.

North Cook Inlet Field

The North Cook Inlet field (fig. 1) is in offshore Cook Inlet about 26 miles southwest of Anchorage.

The North Cook Inlet field was discovered by Amoco Production Co. as a gas-condensate field. The discovery well was spudded in 1962 and, after suffering blowout problems, was completed through a directionally drilled relief well in 1964. Production was from the Tyonek formation at the daily rate of 650 barrels of condensate and 5,000 Mcf of gas. The well and field were shut in from discovery until 1969. In that year, Phillips Petroleum Co., the unit operator, began producing gas from the platform that had been erected in the field. Also in 1969, drilling of the first well of a deep drilling program was begun from the platform.

After Amoco's gas-condensate discovery, oil production from the Hemlock formation was discovered by Shell Oil Co. in a well located about 2-1/2 miles north of Amoco's well. This well has been shut in since discovery, and no plans have been announced by Shell to develop that portion of the field.

Redoubt Shoal Field

In 1968, Amoco Production Co. announced a new field discovery in offshore Cook Inlet south of the Forelands; this is the southernmost oil discovery in the inlet. The discovery well is the only well drilled in the Redoubt Shoal field (fig. 1) to the end of 1969, and it has been shut in since discovery. Production was from the Hemlock formation. No plans have been revealed for future development of the unitized field.

CHARACTERISTICS OF COOK INLET BASIN OILS

Some characteristics of 19 oils from the Cook Inlet Basin are shown in table 9. The unabridged analysis reports on these oils are given in the appendix, and the item number in table 9 is repeated on the reports in the appendix for reference purposes.

Specific gravity and sulfur percentage values show no distinguishable trends that can be related to formation or area. Samples from the nonproducing fields set the extremes of gravity and sulfur content: The condensate from North Cook Inlet has the highest gravity and lowest sulfur content; the oil from Redoubt Shoal has the lowest gravity and highest sulfur. Among oils from the producing fields, the samples from Granite Point have higher gravities and lower sulfur contents than do most of the other oils.

TABLE 9. - Characteristics of some Cook Inlet oils

Item	Field	Productive formation[1]	Depth, feet	Gravity, ° API	Color[2]	Viscosity at 100° F SUS[3]	Pour point, ° F	Sulfur, weight-percent	Nitrogen, weight-percent	Carbon residue, weight-percent[4]	Ratio, nitrogen to carbon residue	Distillation yields, volume-percent				Residuum
												Frac. 1-3 (light gasoline)	Frac. 4-7 (naphtha)	Frac. 8-12 (kerosine, gas-oil)	Frac. 13-15 (lubricating oil)	
1	Cook Inlet, N......	Middle Ground Shoal, cgl.	10,927	53.7	D.G.	29	<5	0.00	0.005	0.1	0.050	29.6	39.4	21.4	5.0	1.7
2	Granite Point......	Middle Ground Shoal, ss..	8,650	42.8	B.G.	34	<5	.02	.039	1.1	.035	17.7	27.4	24.4	13.5	14.4
3	Granite Point......	Middle Ground Shoal, ss..	8,181	40.9	B.G.	34	<5	.05	.054	1.8	.030	15.7	26.8	23.3	13.7	16.2
4	McArthur River.....	Hemlock, cgl............	9,370	33.0	B.G.	45	35	.09	.146	4.3	.034	8.6	21.0	26.3	16.0	27.4
5	McArthur River.....	Hemlock, cgl............	10,662	33.4	G.B.	45	<5	.07	.156	5.1	.031	9.9	20.7	22.0	15.8	29.1
6	McArthur River.....	Hemlock, cgl............	9,486	32.7	B.B.	45	5	.09	.142	4.8	.030	7.6	19.6	26.8	16.5	27.6
7	McArthur River.....	Hemlock, cgl............	10,660	34.2	B.B.	37	20	.08	.132	4.2	.031	8.8	20.6	24.3	15.6	28.6
8	McArthur River.....	Tyonek, cgl.............	11,349	33.0	G.B.	47	35	.11	.149	1.1	.044	6.5	21.1	26.0	18.3	26.4
9	McArthur River.....	West Foreland, ss........	11,350	30.6	B.B.	59	<5	.15	.186	6.8	.027	6.7	19.2	21.9	16.8	31.0
10	Middle Ground Shoal	Middle Ground Shoal, cgl.	8,400	33.8	G.B.	44	<5	.06	.124	4.0	.031	10.1	21.2	26.2	15.6	25.3
11	Middle Ground Shoal	Hemlock, cgl............	7,483	35.0	G.B.	40	<5	.05	.115	3.5	.033	9.1	21.1	26.0	16.2	25.1
12	Redoubt Shoal......	Hemlock, cgl............	10,000	27.7	B.B.	100	10	.22	.211	8.4	.025	8.6	12.7	21.9	15.7	37.5
13	Swanson River......	Hemlock, cgl............	11,000	29.7	B.B.	61	<5	.16	.203	8.1	.025	7.7	19.7	24.9	16.3	31.4
14	Swanson River......	Hemlock, cgl............	10,900	33.8	G.B.	46	10	.05	.133	4.0	.033	12.5	17.8	24.6	15.0	27.8
15	Swanson River......	Hemlock, cgl............	11,200	30.2	G.B.	65	15	.08	.161	7.4	.022	11.2	14.3	24.6	14.6	32.9
16	Swanson River......	Hemlock, cgl.............	11,000	33.4	G.B.	46	10	.05	.133	3.4	.039	9.2	19.8	23.5	16.3	29.1
17	Swanson River......	Hemlock, cgl............	11,000	36.0	G.B.	40	<5	.03	.095	4.3	.022	10.7	23.5	23.6	15.4	24.8
18	Trading Bay........	Middle Ground Shoal, ss..	5,363	31.0	B.B.	53	<5	.05	.149	4.3	.035	9.7	18.8	23.4	16.0	30.5
19	Trading Bay........	Hemlock, cgl............	10,500	32.3	B.G.	45	20	.11	.026	4.7	.028	3.9	25.1	31.1	17.7	26.2

[1]Abbreviation: cgl. = conglomerate; ss. = sandstone.
[2]Colors are designated as follows: D.G. = dark green; B.G. = brownish green; G.B. = greenish black; B.B. = brownish black.
[3]SUS = Saybolt Universal Seconds.
[4]Carbon residue values are equivalent to those obtained by the Conradson method, ASTM designation D189-46.

A notable characteristic of these Cook Inlet oils is the low sulfur content. All of the sulfur percentages are considerably less than 0.5, which is the upper limit proposed for so-called "low-sulfur" oils (12). The highest sulfur percentage is 0.22 percent in the oil from Redoubt Shoal, and all but five of the oils contain less than 0.1 percent.

The nitrogen percentage of the oils, although not high (0.005 to 0.211), has an unusual relationship to the sulfur content. Most crude oils have sulfur contents five to 10 times higher than the nitrogen content. A comparison of sulfur and nitrogen percentages in table 9 shows that all but one of the oils contain more nitrogen than sulfur. Among the few oils with more nitrogen than sulfur are some oils from Utah that are also produced from Tertiary formations (13).

The nitrogen in petroleum has been related to the carbon residue percentage, and therefore to the asphalt content of the oil (1). A study of 153 crude oils showed that 85 percent or more of the nitrogen in the oils remained in the residues after distillation (2). In 1957 at the 131st meeting of the American Chemical Society, Analytical Chemistry Division, J. S. Ball and H. M. Smith presented a paper based on a study of 1,002 crude oils; the average ratio of nitrogen percentages to carbon residue in these oils was found to be 0.050. For the Cook Inlet oils, as shown in table 8, this ratio averages 0.032, which indicates a lower-than-average nitrogen percentage compared with the carbon residue value.

The asphalt content of a crude oil may be estimated from the carbon residue percentage (10); the amount of 100-penetration asphalt that may be obtained from a crude oil is calculated by multiplying the carbon residue percentage by 4.9. A survey of carbon residue percentages in table 9 reveals that these oils will have a wide range of asphalt content, from a low of 0.49 percent for the North Cook Inlet condensate (item 1) to a high of 41 percent for the Redoubt Shoal sample (item 12). Between these extremes the oils average about 21.5 percent asphalt and are considered to be moderately asphaltic.

A few of the oils are waxy, as indicated by their high pour points; for example, items 4, 7, and 8 (table 9) have pour points of 35°, 20°, and 35° F, respectively. These three oils also contain significant carbon residue percentages, which indicate asphalt contents of 15 to 20 percent. Oils that are both waxy and asphaltic are uncommon, although they have been noted in other areas such as the Uinta Basin of Utah (13).

The correlation index (CI) has been used to characterize the molecular structures of the hydrocarbons in petroleum fractions (8-9). The CI scale, a function of the density and boiling range of the fraction, is arranged so that the straight-chain paraffins have an index of zero, and benzene, representing the aromatics, has an index of 100. The branched paraffins, cyclic paraffins (naphthenes), alkyl-substituted aromatics, and mixtures of the various types will have intermediate values.

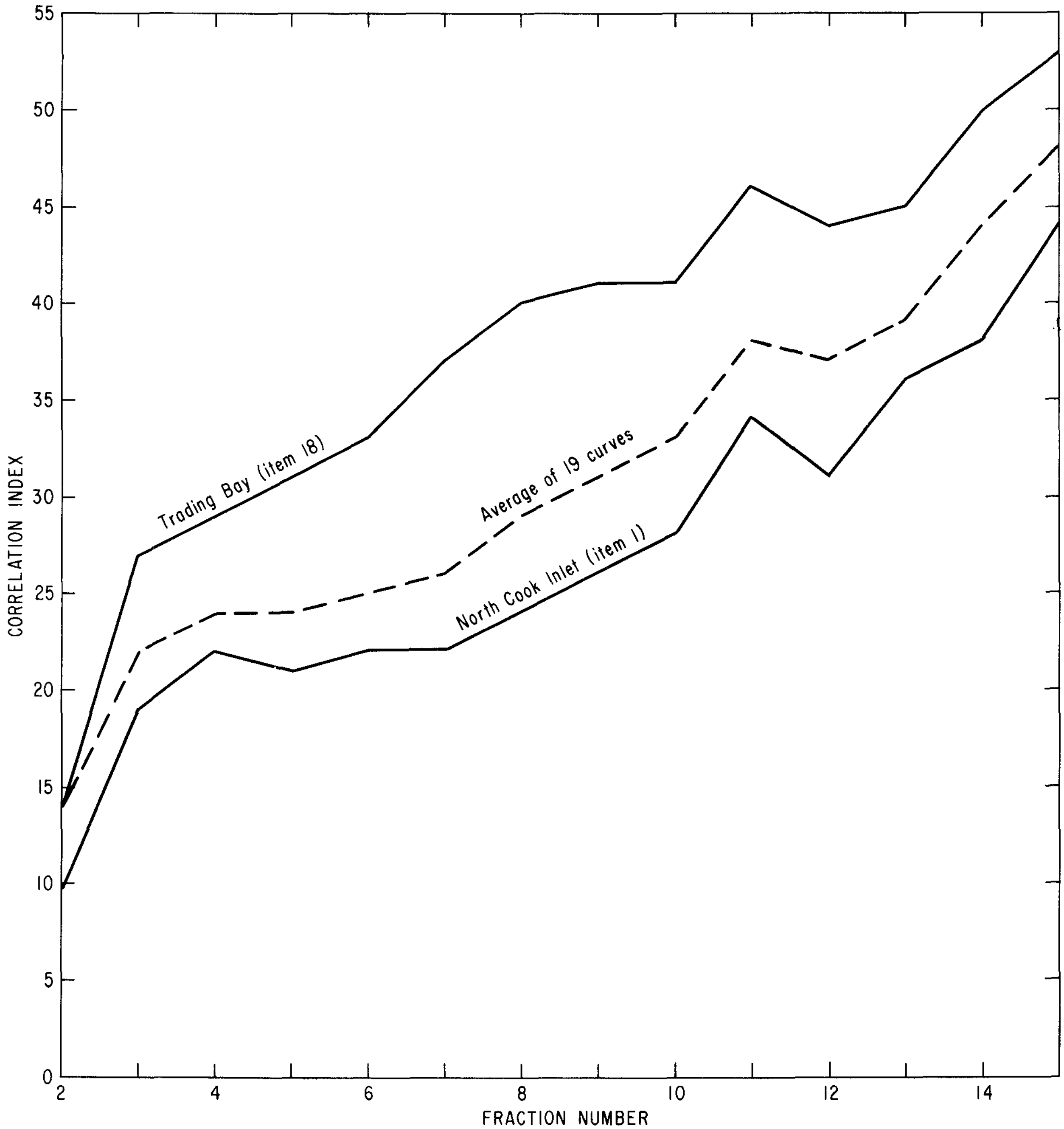


FIGURE 7. - Correlation Index Curves of Cook Inlet Oils.

Correlation index values are plotted in figure 7. The average CI curve for the Cook Inlet oils, obtained by plotting the average values of corresponding fractions of the oils versus the distillation fraction number, is shown in the center. Included in the figure are the upper and lower extremes of the CI curves on fractions of individual oils (items 18 and 1, respectively, in table 8); curves for all other oils have similar shapes and values that fall within these extremes. The relative proximity of the curves and the similarity of their shapes suggest that variations in composition between fractions are not greatly different among the Cook Inlet oils. In each of the oils there is indicated a steady progression from a predominance of open-chain paraffins in the low-boiling fractions toward a predominance of naphthenic and/or aromatic types in the higher boiling ranges.

DISCUSSION

Since the first major discovery in 1957, oil production in the Cook Inlet Basin has boosted Alaska to the status of a major oil-producing State. By the end of 1969, the basin had produced more than 233 million barrels of oil, and annual production rates had reached more than 74 million barrels (table 1). Estimated recoverable reserves, by both primary and secondary recovery methods, are 2.7 billion barrels, which is about 36 percent of the estimated 7.8 billion barrels of oil in place in the basin. Techniques developed by the oil industry to cope successfully with the weather extremes, high tides, and ice floes in the Cook Inlet will doubtless prove of great value in developing oil resources in other parts of Alaska.

All of the Cook Inlet Basin production has been from Tertiary formations. Generally, the reservoir oils have been undersaturated, and repressurization by injection of gas or water has significantly increased the amount of recoverable oil.

Some unusual features may be noted from the analyses of the Cook Inlet oils. In most of the oils, the nitrogen content is higher than the sulfur content. Of interest to petroleum geologists is the occurrence of dark-colored asphaltic oils at depths greater than 10,000 feet, which is a rare instance in other areas (4). It is of further interest to find productive Tertiary formations at these depths; 12 of the 19 oils listed in table 9 are produced from depths of 10,000 feet or greater.

Because of the low sulfur content of the Cook Inlet oils, they should be preferred sources of nonpolluting fuels and should present a minimum of problems for refiners.

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APPENDIX.--UNABRIDGED OIL ANALYSIS REPORTS

Bureau of Mines Laramie Laboratory
Sample PC-65-2

Item 1

IDENTIFICATION

North Cook Inlet field
Middle Ground Shoal Conglomerate-Tertiary
(Tyonek formation)
10,927-10,947 feet

Alaska
Seward Meridian
SW1/4SW1/4, sec. 6,
T 11 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific 0.764 Gravity, ° API, 53.7 Pour point, ° F., below 5
Sulfur, percent, .00 Color, dark green
Viscosity, Saybolt Universal at 100°F, 29 sec Nitrogen, percent, 0.005

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 79 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	5.0	5.0	0.638	90.3					
2	167	9.2	14.2	.675	78.1	9.8	1.37507	125.8		
3	212	15.4	29.6	.716	66.1	19	1.39816	123.0		
4	257	13.9	43.5	.740	59.7	22	1.41018	125.8		
5	302	10.1	53.6	.754	56.2	21	1.41862	127.9		
6	347	8.4	62.0	.770	52.3	22	1.42727	130.3		
7	392	7.0	69.0	.784	49.0	22	1.43495	130.6		
8	437	5.9	74.9	.800	45.4	24	1.44264	130.0		
9	482	4.4	79.3	.815	42.1	26	1.45054	134.4		
10	527	5.5	84.8	.830	39.0	28	1.45889	140.3		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	2.2	87.0	.850	35.0	34	1.46763	142.6	37	5
12	437	3.4	90.4	.852	34.6	31	1.47129	144.1	44	25
13	482	1.6	92.0	.870	31.1	36	1.47757	145.7	53	45
14	527	1.6	93.6	.881	29.1	38			65	60
15	572	1.8	95.4	.899	25.9	44			110	65
Residuum		1.7	97.1	.948	17.8					

Carbon residue, Conradson: Residuum, 4.8 percent; crude, 0.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	29.6	0.690	73.6	
Total gasoline and naphtha	69.0	.729	62.6	
Kerosine distillate	10.3	.806	44.1	
Gas oil	11.2	.844	36.2	
Nonviscous lubricating distillate	3.6	.865-.894	32.1-26.8	50-100
Medium lubricating distillate	1.3	.894-.907	26.8-24.5	100-200
Viscous lubricating distillate				Above 200
Residuum	1.7	.948	17.8	
Distillation loss	2.9			

Bureau of Mines Laramie Laboratory
Sample PC-65-77

Item 2

IDENTIFICATION

Granite Point field
Middle Ground Shoal sandstone-Tertiary
(Tyonek formation)
8,650-8,770 feet

Alaska
Seward Meridian
SW1/4NW1/4, sec. 13,
T 10 N, R 12 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.812 Gravity, ° API, 42.8 Pour point, ° F., below 5
Sulfur, percent, .02 Color, brownish green
Viscosity, Saybolt Universal at 100° F., 34 sec. Nitrogen, percent, 0.039

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 81 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	6.0	6.0	0.657	83.9					
2	167	3.1	9.1	.689	73.9	17	1.38532	126.9		
3	212	8.6	17.7	.725	63.7	24	1.40158	129.8		
4	257	9.4	27.1	.746	58.2	25	1.41337	131.0		
5	302	6.4	33.5	.763	54.0	25	1.42395	134.4		
6	347	6.5	40.0	.779	50.1	26	1.43201	136.6		
7	392	5.1	45.1	.793	46.9	26	1.44012	136.4		
8	437	5.5	50.6	.811	43.0	29	1.44922	141.0		
9	482	5.5	56.1	.827	39.6	31	1.45895	146.2		
10	527	7.2	63.3	.841	36.8	33	1.46699	152.4		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.3	64.6	.861	32.8	39	1.47562	155.2	40	10
12	437	4.9	69.5	.864	32.3	37	1.47809	157.1	43	20
13	482	4.7	74.2	.875	30.2	38	1.48451	159.7	53	35
14	527	3.9	78.1	.895	26.6	45			70	60
15	572	4.9	83.0	.907	24.5	47			110	80
Residuum		14.4	97.4	.964	15.3					

Carbon residue, Conradson: Residuum, 6.4 percent; crude, 1.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	17.7	0.696	71.8	
Total gasoline and naphtha	45.1	.739	60.0	
Kerosine distillate	5.5	.811	43.0	
Gas oil	19.7	.846	35.8	
Nonviscous lubricating distillate	8.9	.872-.904	30.8-25.0	50-100
Medium lubricating distillate	3.8	.904-.914	25.0-23.3	100-200
Viscous lubricating distillate				Above 200
Residuum	14.4	.964	15.3	
Distillation loss	2.6			

Bureau of Mines Laramie Laboratory
Sample PC-66-13

Item 3

IDENTIFICATION

Granite Point field
Middle Ground Shoal sandstone -Tertiary
(Tyonek formation)
8,181-8,570 feet

Alaska
Seward Meridian
SE1/4SE1/4, sec. 1,
T 10 N, R 12 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.821 Gravity, ° API, 40.9 Pour point, ° F., below 5
Sulfur, percent, .05 Color, brownish green
Viscosity, Saybolt Universal at 100°F., 34 sec. Nitrogen, percent, 0.054

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 86 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	3.7	3.7	0.652	85.5					
2	167	4.0	7.7	.671	79.4	8.0	1.37796	123.4		
3	212	8.0	15.7	.720	65.0	21	1.39996	122.8		
4	257	9.0	24.7	.742	59.2	23	1.41148	125.7		
5	302	6.5	31.2	.758	55.2	23	1.42134	127.8		
6	347	6.0	37.2	.775	51.1	24	1.43087	132.6		
7	392	5.3	42.5	.790	47.6	25	1.43856	132.8		
8	437	5.4	47.9	.806	44.1	27	1.44663	133.5		
9	482	5.7	53.6	.822	40.6	29	1.45668	141.8		
10	527	6.6	60.2	.839	37.2	32	1.46545	147.3		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	.9	61.1	.861	32.8	39	1.47659	150.1	43	15
12	437	4.7	65.8	.863	32.5	36	1.47865	155.1	44	25
13	482	4.7	70.5	.873	30.6	37	1.48436	157.6	52	45
14	527	4.1	74.6	.891	27.3	43			71	65
15	572	4.9	79.5	.903	25.2	46			120	80
Residuum		16.2	95.7	.967	14.8					

Carbon residue, Conradson: Residuum, 9.4 percent; crude, 1.8 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	15.7	0.691	73.3	
Total gasoline and naphtha	42.5	.736	60.8	
Kerosine distillate	11.1	.814	42.3	
Gas oil	13.4	.853	34.4	
Nonviscous lubricating distillate	8.1	.871-.898	31.0-26.1	50-100
Medium lubricating distillate	4.4	.898-.910	26.1-24.0	100-200
Viscous lubricating distillate				Above 200
Residuum	16.2	.967	14.8	
Distillation loss	4.3			

Bureau of Mines Laramie Laboratory
Sample PC-66-14

IDENTIFICATION

Item 4

McArthur River field
Hemlock conglomerate-Tertiary
9,370-9,770 feet

Alaska
Seward Meridian
NW1/4SE1/4, sec. 29,
T 9 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.860 Gravity, ° API, 33.0 Pour point, ° F., 35
Sulfur, percent, .09 Color, brownish green
Viscosity, Saybolt Universal at 100°F., 45 sec. Nitrogen, percent, 0.146

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 90 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.2	1.2	0.671	79.4					
2	167	2.1	3.3	.676	77.8	10	1.37987	124.7		
3	212	5.3	8.6	.720	65.0	21	1.39966	126.1		
4	257	5.7	14.3	.743	58.9	23	1.41195	128.1		
5	302	6.3	20.6	.760	54.7	24	1.42233	132.4		
6	347	4.5	25.1	.777	50.6	25	1.43104	136.1		
7	392	4.5	29.6	.792	47.2	26	1.43917	135.5		
8	437	4.7	34.3	.809	43.4	28	1.44806	136.3		
9	482	5.5	39.8	.825	40.0	31	1.45749	147.5		
10	527	6.8	46.6	.841	36.8	33	1.46720	151.8		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	3.8	50.4	.857	33.6	37	1.47592	156.1	39	10
12	437	5.5	55.9	.863	32.5	36	1.47988	158.4	45	25
13	482	5.3	61.2	.876	30.0	39	1.48632	159.4	52	40
14	527	5.0	66.2	.895	26.6	45			69	55
15	572	5.7	71.9	.907	24.5	47			120	75
Residuum		27.4	99.3	.986	12.0					

Carbon residue, Conradson: Residuum, 13.7 percent; crude, 4.3 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	8.6	0.702	70.1	
Total gasoline and naphtha	29.6	.747	57.9	
Kerosine distillate	10.2	.818	41.5	
Gas oil	16.9	.854	34.2	
Nonviscous lubricating distillate	10.2	.872-.902	30.8-25.4	50-100
Medium lubricating distillate	5.0	.902-.914	25.4-23.3	100-200
Viscous lubricating distillate				Above 200
Residuum	27.4	.986	12.0	
Distillation loss	.7			

Bureau of Mines Laramie Laboratory
Sample PC-66-62

IDENTIFICATION

Item 5

McArthur River field
Hemlock conglomerate-Tertiary
10,662-10,824 feet

Alaska
Seward Meridian
NW1/4NE1/4, sec. 4,
T 8 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.858 Gravity, ° API, 33.4 Pour point, ° F., below 5
Sulfur, percent, .07 Color, greenish black
Viscosity, Saybolt Universal at 100°F, 45 sec. Nitrogen, percent, 0.156

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 84 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.9	2.9	0.674	78.4					
2	167	2.7	5.6	.692	73.0	18	1.38526	120.9		
3	212	4.3	9.9	.724	63.9	23	1.40116	126.5		
4	257	5.6	15.5	.745	58.4	24	1.41301	128.1		
5	302	5.4	20.9	.760	54.7	24	1.42250	134.8		
6	347	4.3	25.2	.779	50.1	26	1.43138	136.5		
7	392	5.4	30.6	.794	46.7	27	1.43934	136.7		
8	437	3.4	34.0	.811	43.0	29	1.44823	141.4		
9	482	5.0	39.0	.827	39.6	31	1.45819	148.7		
10	527	6.6	45.6	.841	36.8	33	1.46752	157.0		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.8	47.4	.861	32.8	39	1.47633	158.0	39	5
12	437	5.2	52.6	.865	32.1	37	1.47886	160.9	42	10
13	482	5.4	58.0	.875	30.2	38	1.48476	161.0	51	25
14	527	5.0	63.0	.890	27.5	42			67	50
15	572	5.4	68.4	.902	25.4	45			110	70
Residuum	......	29.1	97.5	.988	11.7					

Carbon residue, Conradson: Residuum, 15.2 percent; crude, 5.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	9.9	0.701	70.4	
Total gasoline and naphtha	30.6	.747	57.9	
Kerosine distillate	3.4	.811	43.0	
Gas oil	20.6	.849	35.2	
Nonviscous lubricating distillate	9.9	.874-.899	30.4-25.9	50-100
Medium lubricating distillate	3.9	.899-.908	25.9-24.3	100-200
Viscous lubricating distillate				Above 200
Residuum	29.1	.988	11.7	
Distillation loss	2.5			

Bureau of Mines Laramie Laboratory
Sample PC-66-66

IDENTIFICATION

Item 6

McArthur River field
Hemlock conglomerate-Tertiary
9,486-9,600 feet

Alaska
Seward Meridian
NW1/4NW1/4, sec. 19,
T 9 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.862 Gravity, ° API, 32.7 Pour point, ° F., 5
Sulfur, percent, .09 Color, brownish black
Viscosity, Saybolt Universal at 100°F, 45 sec; at 77°F, 51 sec. Nitrogen, percent, 0.142

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 88 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.1	2.1	0.704	69.5					
2	167	1.5	3.6	.679	76.9	12	1.38645	123.1		
3	212	4.0	7.6	.719	65.3	21	1.40044	124.6		
4	257	6.1	13.7	.742	59.2	23	1.41160	126.5		
5	302	4.3	18.0	.758	55.2	23	1.42076	131.5		
6	347	4.7	22.7	.773	51.6	23	1.42910	134.1		
7	392	4.5	27.2	.789	47.8	24	1.43748	137.2		
8	437	4.7	31.9	.807	43.8	27	1.44707	137.1		
9	482	5.0	36.9	.823	40.4	30	1.45636	144.5		
10	527	6.9	43.8	.839	37.2	32	1.46556	153.0		

STAGE 2—Distillation continued at 40 mm. Hg

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
11	392	4.2	48.0	.857	33.6	37	1.47536	156.5	38	5
12	437	6.0	54.0	.864	32.3	37	1.47956	168.1	44	20
13	482	4.9	58.9	.877	29.9	39	1.48682	162.4	54	35
14	527	5.5	64.4	.900	25.7	47			75	65
15	572	6.1	70.5	.924	21.6	55			135	80
Residuum		27.6	98.1	.989	11.6					

Carbon residue, Conradson: Residuum, 15.1 percent; crude, 4.8 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	7.6	0.707	68.6	
Total gasoline and naphtha	27.2	.748	57.7	
Kerosine distillate	9.7	.815	42.1	
Gas oil	17.3	.853	34.4	
Nonviscous lubricating distillate	9.8	.872-.910	30.8-24.0	50-100
Medium lubricating distillate	6.5	.910-.937	24.0-19.5	100-200
Viscous lubricating distillate				Above 200
Residuum	27.6	.989	11.6	
Distillation loss	1.9			

Bureau of Mines Laramie Laboratory
Sample PC-66-67

IDENTIFICATION

Item 7

McArthur River field
Hemlock conglomerate-Tertiary
10,660-10,857 feet

Alaska
Seward Meridian
SE1/4SE1/4, sec. 18,
T 8 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.854 Gravity, ° API, 34.2 Pour point, ° F., 20
Sulfur, percent, .08 Color, brownish black
Viscosity, Saybolt Universal at 100°F, 37 sec; at 77°F, 49 sec. Nitrogen, percent, 0.132

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 84 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.1	2.1	0.716	66.1					
2	167	2.3	4.4	.672	79.1	8.4	1.38011	120.1		
3	212	4.4	8.8	.717	65.9	20	1.39816	127.2		
4	257	6.0	14.8	.742	59.2	23	1.41166	127.4		
5	302	5.2	20.0	.758	55.2	23	1.42088	128.5		
6	347	5.0	25.0	.775	51.1	24	1.43041	133.3		
7	392	4.4	29.4	.791	47.4	25	1.43906	134.9		
8	437	4.7	34.1	.809	43.4	28	1.44801	137.5		
9	482	5.2	39.3	.824	40.2	30	1.45717	145.6		
10	527	6.7	46.0	.839	37.2	32	1.46598	154.5		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	2.6	48.6	.860	33.0	38	1.47587	153.9	37	below 5
12	437	5.1	53.7	.862	32.7	36	1.47824	157.6	43	20
13	482	5.3	59.0	.872	30.8	37	1.48431	161.4	51	35
14	527	5.1	64.1	.891	27.3	43			68	55
15	572	5.2	69.3	.911	23.8	49			110	75
Residuum		28.6	97.9	.977	13.3					

Carbon residue, Conradson: Residuum, 13.1 percent; crude, 4.2 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	8.8	0.705	69.2	
Total gasoline and naphtha	29.4	.747	57.9	
Kerosine distillate	9.9	.817	41.7	
Gas oil	16.0	.853	34.4	
Nonviscous lubricating distillate	10.0	.870-.905	31.1-24.9	50-100
Medium lubricating distillate	4.0	905-.921	24.9-22.1	100-200
Viscous lubricating distillate				Above 200
Residuum	28.6	.977	13.3	
Distillation loss	2.1			

Bureau of Mines Laramie Laboratory
Sample PC-70-300

IDENTIFICATION

Item 8

McArthur River field
Tyonek Conglomerate-Tertiary
11,349 feet (approximate)

Alaska
Seward Meridian
SW1/4NW1/4, sec 33,
T 9 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.860 Gravity, ° API, 33.0 Pour point, ° F., 35
Sulfur, percent, .11 Color, greenish black
Viscosity, Saybolt Universal at 100° F, 47 sec; at 77° F, 60 sec. Nitrogen, percent, 0.149

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 91 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	0.8	0.8							
2	167	1.5	2.3	0.686	74.8	15	1.38728	127.7		
3	212	4.2	6.5	.721	64.8	22	1.40236	125.5		
4	257	6.5	13.0	.740	59.7	22	1.41065	130.8		
5	302	5.0	18.0	.758	55.2	23	1.41989	133.8		
6	347	5.1	23.1	.773	51.6	23	1.42853	133.9		
7	392	4.5	27.6	.790	47.6	25	1.43720	135.5		
8	437	5.6	33.2	.809	43.4	28	1.44685	138.8		
9	482	4.4	37.6	.824	40.2	30	1.45582	143.9		
10	527	7.0	44.6	.837	37.6	32	1.46392	152.3		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	3.0	47.6	.851	34.8	34	1.47406	153.5	38	10
12	437	6.0	53.6	.862	32.7	36	1.47768	156.8	43	30
13	482	5.2	58.8	.873	30.6	37	1.48400	158.8	52	50
14	527	5.0	63.8	.887	28.0	41			69	70
15	572	8.1	71.9	.904	25.0	46			110	95
Residuum		26.4	98.3	.982	12.6					

Carbon residue, Conradson: Residuum, 3.6 percent; crude, 1.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	6.5	0.709	68.1	
Total gasoline and naphtha	27.6	.750	57.2	
Kerosine distillate	10.0	.816	41.9	
Gas oil	17.4	.850	35.0	
Nonviscous lubricating distillate	11.3	.871-.900	31.0-25.7	50-100
Medium lubricating distillate	5.6	.900-.915	25.7-23.1	100-200
Viscous lubricating distillate				Above 200
Residuum	26.4	.982	12.6	
Distillation loss	1.7			

Bureau of Mines Laramie Laboratory
Sample PC-70-301

IDENTIFICATION

Item 9

McArthur River field
West Foreland sandstone - Tertiary
11,350 feet (approximate)

Alaska
Seward Meridian
SW1/4NW1/4, sec 33,
T 9 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.873 Gravity, ° API, 30.6 Pour point, ° F., below 5
Sulfur, percent, .15 Color, brownish black
Viscosity, Saybolt Universal at 100°F., 59 sec; at 77°F., 67 sec Nitrogen, percent, 0.186

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 129 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122									
2	167	1.3	1.3	0.676	77.8		1.38441	128.1		
3	212	5.4	6.7	.723	64.2	23	1.40146	134.5		
4	257	4.1	10.8	.744	58.7	24	1.41236	127.3		
5	302	4.7	15.5	.758	55.2	23	1.41978	130.5		
6	347	5.0	20.5	.779	50.1	26	1.43161	132.8		
7	392	5.4	25.9	.798	45.8	29	1.44147	135.0		
8	437	3.8	29.7	.817	41.7	32	1.45152	142.7		
9	482	5.3	35.0	.831	38.8	33	1.45996	145.2		
10	527	6.8	41.8	.844	36.2	35	1.46831	153.4		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.6	43.4	.862	32.7	39	1.47834	157.0	41	10
12	437	4.4	47.8	.868	31.5	38	1.48075	160.1	44	15
13	482	5.8	53.6	.878	29.7	40	1.48717	162.4	57	45
14	527	4.9	58.5	.889	27.7	42			73	60
15	572	6.1	64.6	.903	25.2	46			125	70
Residuum		31.0	95.6	1.002	9.7					

Carbon residue, Conradson: Residuum, 19.1 percent; crude, 6.8 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	6.7	0.714	66.7	
Total gasoline and naphtha	25.9	.757	55.4	
Kerosine distillate	3.8	.817	41.7	
Gas oil	18.3	.848	35.4	
Nonviscous lubricating distillate	10.8	.873-.896	30.6-26.4	50-100
Medium lubricating distillate	5.8	.896-.911	26.4-23.8	100-200
Viscous lubricating distillate				Above 200
Residuum	31.0	1.002	9.7	
Distillation loss	4.4			

Bureau of Mines Laramie Laboratory
Sample PC-65-1

IDENTIFICATION

Item 10

Middle Ground Shoal field
Middle Ground Shoal conglomerate-Tertiary
(Tyonek formation)
8,400-8,865 feet

Alaska
Seward Meridian
SW1/4NW1/4, sec. 31,
T 9 N, R 12 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.856 Gravity, ° API, 33.8 Pour point, ° F., below 5
Sulfur, percent, .06 Color, greenish black
Viscosity, Saybolt Universal at 100°F., 44 sec Nitrogen, percent, 0.124

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 79 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.8	1.8	0.656	84.2					
2	167	2.6	4.4	.685	75.1	15	1.38502	129.2		
3	212	5.7	10.1	.727	63.1	25	1.40325	127.2		
4	257	5.6	15.7	.746	58.2	25	1.41371	132.1		
5	302	5.4	21.1	.763	54.0	25	1.42372	136.0		
6	347	5.2	26.3	.779	50.1	26	1.43235	136.0		
7	392	5.0	31.3	.795	46.5	27	1.44141	137.7		
8	437	4.4	35.7	.813	42.6	30	1.45081	139.7		
9	482	5.8	41.5	.829	39.2	32	1.46023	148.8		
10	527	8.0	49.5	.845	36.0	35	1.46988	156.4		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.8	51.3	.864	32.3	40	1.47768	157.7	39	5
12	437	6.2	57.5	.866	31.9	37	1.48059	160.4	44	20
13	482	7.0	64.5	.880	29.3	41	1.48877	176.0	56	40
14	527	3.8	68.3	.900	25.7	47			82	60
15	572	4.8	73.1	.912	23.7	50			135	65
Residuum		25.3	98.4	.985	12.2					

Carbon residue, Conradson: Residuum, 13.7 percent; crude, 4.0 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	10.1	0.703	69.8	
Total gasoline and naphtha	31.3	.748	57.7	
Kerosine distillate	4.4	.813	42.6	
Gas oil	22.1	.849	35.2	
Nonviscous lubricating distillate	10.0	.873-.905	30.6-24.9	50-100
Medium lubricating distillate	5.3	.905-.918	24.9-22.6	100-200
Viscous lubricating distillate				Above 200
Residuum	25.3	.985	12.2	
Distillation loss	1.6			

Bureau of Mines Laramie Laboratory
Sample PC-65-49

Item 11

IDENTIFICATION

Middle Ground Shoal field
Hemlock conglomerate-Tertiary
7,483-8,177 feet

Alaska
Seward Meridian
SE1/4NW1/4, sec. 1,
T 8 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.850 Gravity, ° API, 35.0 Pour point, ° F., below 5
Sulfur, percent, .05 Color, greenish black
Viscosity, Saybolt Universal at 100°F, 40 sec. Nitrogen, percent, 0.115

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 84 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.7	1.7	0.650	86.2					
2	167	2.4	4.1	.675	78.1	9.8	1.38282	121.6		
3	212	5.0	9.1	.722	64.5	22	1.40134	124.4		
4	257	6.0	15.1	.745	58.4	24	1.41231	131.0		
5	302	5.2	20.3	.761	54.4	24	1.42198	134.5		
6	347	5.1	25.4	.777	50.6	25	1.43109	136.9		
7	392	4.8	30.2	.794	46.7	27	1.43962	138.2		
8	437	5.0	35.2	.812	42.8	30	1.44955	140.8		
9	482	5.5	40.7	.829	39.2	32	1.45953	151.4		
10	527	6.5	47.2	.844	36.2	35	1.46904	158.8		

STAGE 2—Distillation continued at 40 mm. Hg

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
11	392	3.2	50.4	.861	32.8	39	1.47793	162.0	38	5
12	437	5.8	56.2	.867	31.7	38	1.48090	162.7	43	20
13	482	6.3	62.5	.880	29.3	41	1.48832	166.9	54	50
14	527	5.0	67.5	.898	26.1	46			74	65
15	572	4.9	72.4	.908	24.3	48			130	80
Residuum	......	25.1	97.5	.983	12.5					

Carbon residue, Conradson: Residuum, 12.0 percent; crude, 3.5 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	9.1	0.696	71.8	
Total gasoline and naphtha	30.2	.746	58.2	
Kerosine distillate	5.0	.812	42.8	
Gas oil	21.6	.850	35.0	
Nonviscous lubricating distillate	10.5	.874-.903	30.4-25.2	50-100
Medium lubricating distillate	5.1	.903-.913	25.2-23.5	100-200
Viscous lubricating distillate				Above 200
Residuum	25.1	.983	12.5	
Distillation loss	2.5			

Bureau of Mines Laramie Laboratory
Sample PC-69-278

IDENTIFICATION

Item 12

Redoubt Shoal Field
Hemlock Conglomerate - Tertiary
10,000 Feet (approximate)

Alaska
Seward Meridian
NW1/4, sec 19,
T7N, R13W

GENERAL CHARACTERISTICS

Gravity, specific, 0.889 Gravity, ° API, 27.7 Pour point, ° F., 10
Sulfur, percent, .22 Color, brownish black
Viscosity, Saybolt Universal at 100° F, 100 sec; at 130° F, 63 sec Nitrogen, percent, 0.211

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

Stage 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 88 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	0.9	0.9	0.890	27.5					
2	167	3.3	4.2	.738	60.2	40	1.42117	145.6		
3	212	4.4	8.6	.739	60.0	30	1.40853	128.0		
4	257	2.9	11.5	.760	54.7	31	1.41943	127.8		
5	302	2.9	14.4	.766	53.2	27	1.42308	131.5		
6	347	3.4	17.8	.776	50.9	24	1.43001	134.6		
7	392	3.5	21.3	.793	46.9	26	1.43867	135.2		
8	437	3.4	24.7	.810	43.2	29	1.44718	139.3		
9	482	4.3	29.0	.825	40.0	31	1.45652	144.6		
10	527	6.4	35.4	.840	37.0	33	1.46566	152.4		

Stage 2—Distillation continued at 40 mm. Hg

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
11	392	2.4	37.8	.863	32.5	40	1.47690	149.1	39	below 5
12	437	5.4	43.2	.866	31.9	37	1.48044	151.4	44	25
13	482	5.1	48.3	.879	29.5	40	1.48727	165.2	53	45
14	527	5.5	53.8	.899	25.9	47			77	65
15	572	5.1	58.9	.909	24.2	48			145	85
Residuum		37.5	96.4	1.005	9.3					

Carbon residue, Conradson: Residuum, 19.8 percent; crude, 8.4 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	8.6	0.754	56.2	
Total gasoline and naphtha	21.3	.766	53.2	
Kerosine distillate	7.7	.818	41.5	
Gas oil	14.8	.856	33.8	
Nonviscous lubricating distillate	9.0	.875-.903	30.2-25.2	50-100
Medium lubricating distillate	6.1	.903-.914	25.2-23.3	100-200
Viscous lubricating distillate				Above 200
Residuum	37.5	1.005	9.3	
Distillation loss	3.6			

Bureau of Mines Laramie Laboratory
Sample PC-58-352

Item 13

IDENTIFICATION

Swanson River field
Hemlock conglomerate-Tertiary
11,000 feet (approximate)

Alaska
Seward Meridian
SW1/4SE1/4, sec. 10,
T 8 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.878 Gravity, ° API, 29.7° Pour point, ° F., below 5
Sulfur, percent, 0.16 Color, brownish black
Viscosity, Saybolt Universal at 100°F., 61 Sec.; at 77°F., 105 sec Nitrogen, percent, 0.203

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 79 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum. percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.9	1.9	0.655	84.5					
2	167	2.9	4.8	.697	71.5	20	1.38618	126.4		
3	212	2.9	7.7	.725	63.7	24	1.40248	126.5		
4	257	5.2	12.9	.737	60.5	20	1.41024	128.8		
5	302	6.0	18.9	.756	55.7	22	1.41925	130.1		
6	347	4.5	23.4	.773	51.6	23	1.42893	133.3		
7	392	4.0	27.4	.790	47.6	25	1.43788	138.5		
8	437	4.3	31.7	.807	43.8	27	1.44685	141.2		
9	482	4.8	36.5	.822	40.6	29	1.45673	149.3		
10	527	6.7	43.2	.837	37.6	32	1.46715	156.4		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	3.2	46.4	0.858	33.4	37	1.47582	158.3	39	10
12	437	5.9	52.3	.864	32.3	37	1.48024	162.4	45	20
13	482	5.3	57.6	.878	29.7	40	1.48757	161.8	56	45
14	527	4.6	62.2	.900	25.7	47			83	65
15	572	6.4	68.6	.912	23.7	50			155	80
Residuum		31.4	100.0	1.016	7.8					

Carbon residue, Conradson: Residuum, 22.3 percent; crude, 8.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	7.7	0.697	71.5	
Total gasoline and naphtha	27.4	.744	58.7	
Kerosine distillate	9.1	.815	42.1	
Gas oil	15.4	.852	34.6	
Nonviscous lubricating distillate	9.3	.870-.903	31.1-25.2	50-100
Medium lubricating distillate	7.4	.903-.919	25.2-22.5	100-200
Viscous lubricating distillate				Above 200
Residuum	31.4	1.016	7.8	
Distillation loss	.0			

Bureau of Mines Laramie Laboratory
Sample PC-65-72 Item 14

IDENTIFICATION

Swanson River field (Soldotna Creek)
Hemlock conglomerate-Tertiary
10,900 feet (approximate)

Alaska
Seward Meridian
SE1/4SE1/4, sec. 33,
T 8 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.856 Gravity, ° API, 33.8 Pour point, ° F., 10
Sulfur, percent, .05 Color, greenish black
Viscosity, Saybolt Universal at 100°F, 46 sec. Nitrogen, percent, 0.133

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 84 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.3	2.3	0.690	73.6					
2	167	3.6	5.9	.687	74.5	16	1.38532	127.2		
3	212	6.6	12.5	.730	62.3	26	1.40408	123.7		
4	257	4.1	16.6	.749	57.4	26	1.41494	126.2		
5	302	4.4	21.0	.761	54.4	24	1.42169	132.9		
6	347	4.9	25.9	.776	50.9	24	1.43018	133.0		
7	392	4.4	30.3	.792	47.2	26	1.43828	136.0		
8	437	5.3	35.6	.809	43.4	28	1.44762	140.4		
9	482	4.9	40.5	.826	39.8	31	1.45776	146.7		
10	527	7.1	47.6	.842	36.6	34	1.46672	155.5		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.3	48.9	.862	32.7	39	1.47536	156.7	41	10
12	437	6.0	54.9	.864	32.3	37	1.47819	159.1	43	25
13	482	5.1	60.0	.874	30.4	38	1.48451	159.9	53	50
14	527	4.6	64.6	.892	27.1	43			74	65
15	572	5.3	69.9	.903	25.2	46			120	80
Residuum		27.8	97.7	.993	11.0					

Carbon residue, Conradson: Residuum, 12.4 percent; crude, 4.0 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	12.5	0.710	67.8	
Total gasoline and naphtha	30.3	.745	58.4	
Kerosine distillate	5.3	.809	43.4	
Gas oil	20.1	.848	35.4	
Nonviscous lubricating distillate	9.4	.871-.898	31.0-26.1	50-100
Medium lubricating distillate	4.8	.898-.909	26.1-24.2	100-200
Viscous lubricating distillate				Above 200
Residuum	27.8	.993	11.0	
Distillation loss	2.3			

Bureau of Mines Laramie Laboratory
Sample PC-65-73

IDENTIFICATION

Item 15

Swanson River field
Hemlock conglomerate-Tertiary
11,200 feet (approximate)

Alaska
Seward Meridian
SE1/4SW1/4, sec. 15,
T 8 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.875 Gravity, ° API, 30.2 Pour point, ° F., 15
Sulfur, percent, .08 Color, greenish black
Viscosity, Saybolt Universal at 100°F, 65 sec; at 77°F, 74 sec. Nitrogen, percent, 0.161

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 84 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.5	1.5	0.676	77.8					
2	167	4.9	6.4	.701	70.4	22	1.39063	125.7		
3	212	4.8	11.2	.732	61.8	27	1.40563	127.7		
4	257	2.2	13.4	.748	57.7	26	1.41442	125.4		
5	302	3.6	17.0	.759	54.9	23	1.42065	130.6		
6	347	4.4	21.4	.774	51.3	23	1.42898	131.7		
7	392	4.1	25.5	.790	47.6	25	1.43709	134.0		
8	437	4.3	29.8	.805	44.3	26	1.44548	139.6		
9	482	4.8	34.6	.823	40.4	30	1.45484	143.2		
10	527	6.3	40.9	.837	37.6	32	1.46360	150.3		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	3.0	43.9	.858	33.4	37	1.47473	155.6	40	10
12	437	6.2	50.1	.864	32.3	37	1.47865	160.3	45	25
13	482	4.0	54.1	.876	30.0	39	1.48461	162.5	54	45
14	527	6.1	60.2	.890	27.5	42			76	65
15	572	4.5	64.7	.906	24.7	47			130	80
Residuum		32.9	97.6	1.003	9.6					

Carbon residue, Conradson: Residuum, 19.6 percent; crude, 7.4 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	11.2	0.711	67.5	
Total gasoline and naphtha	25.5	.745	58.4	
Kerosine distillate	9.1	.814	42.3	
Gas oil	15.1	.853	34.4	
Nonviscous lubricating distillate	9.7	.871-.897	31.0-26.3	50-100
Medium lubricating distillate	5.3	.897-.913	26.3-23.5	100-200
Viscous lubricating distillate				Above 200
Residuum	32.9	1.003	9.6	
Distillation loss	2.4			

Bureau of Mines Laramie Laboratory
Sample PC-65-74

IDENTIFICATION

Item 16

Swanson River field
Hemlock conglomerate-Tertiary
11,000 feet (approximate)

Alaska
Seward Meridian
NE1/4NW1/4, sec. 34,
T 8 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.858 Gravity, ° API, 33.4 Pour point, ° F., 10
Sulfur, percent, .05 Color, greenish black
Viscosity, Saybolt Universal at 100°F., 46 sec. Nitrogen, percent, 0.133

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 82 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.8	2.8	0.650	86.2					
2	167	2.5	5.3	.690	73.6	17	1.38807	124.5		
3	212	3.9	9.2	.720	65.0	21	1.39984	126.1		
4	257	6.1	15.3	.741	59.5	22	1.41018	131.3		
5	302	4.6	19.9	.758	55.2	23	1.42012	133.0		
6	347	4.8	24.7	.775	51.1	24	1.42955	134.6		
7	392	4.3	29.0	.792	47.2	26	1.43844	136.2		
8	437	4.7	33.7	.808	43.6	28	1.44696	139.7		
9	482	5.5	39.2	.824	40.2	30	1.45636	146.7		
10	527	6.8	46.0	.840	37.0	33	1.46635	153.8		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.4	47.4	.859	33.2	38	1.47437	155.9	39	10
12	437	5.1	52.5	.862	32.7	36	1.47731	156.1	41	20
13	482	5.1	57.6	.872	30.8	37	1.48330	160.5	51	40
14	527	4.8	62.4	.894	26.8	44			67	60
15	572	6.4	68.8	.915	23.1	51			110	80
Residuum		29.1	97.9	.992	11.1					

Carbon residue, Conradson: Residuum, 10.1 percent; crude, 3.4 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	9.2	0.691	73.3	
Total gasoline and naphtha	29.0	.741	59.5	
Kerosine distillate	10.2	.817	41.7	
Gas oil	15.0	.854	34.2	
Nonviscous lubricating distillate	10.0	.871-.910	31.0-24.0	50-100
Medium lubricating distillate	4.6	.910-.927	24.0-21.1	100-200
Viscous lubricating distillate				Above 200
Residuum	29.1	.992	11.1	
Distillation loss	2.1			

Bureau of Mines Laramie Laboratory
Sample PC-65-75

Item 17

IDENTIFICATION

Swanson River field (Soldotna Creek)
Hemlock conglomerate-Tertiary
11,000 feet (approximate)

Alaska
Seward Meridian
NW1/4, sec. 16,
T 7 N, R 9 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.845 Gravity, ° API, 36.0 Pour point, ° F., below 5
Sulfur, percent, .03 Color, greenish black
Viscosity, Saybolt Universal at 100 °F., 40 sec. Nitrogen, percent, 0.095

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 82 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum. percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	2.6	2.6	0.651	85.9					
2	167	2.7	5.3	.675	78.1	9.8	1.37827	122.6		
3	212	5.4	10.7	.721	64.8	22	1.40068	120.9		
4	257	8.3	19.0	.750	57.2	27	1.42123	134.6		
5	302	5.4	24.4	.761	54.4	24	1.42198	132.1		
6	347	4.9	29.3	.777	50.6	25	1.43064	134.4		
7	392	4.9	34.2	.790	47.6	25	1.43783	137.8		
8	437	4.7	38.9	.807	43.8	27	1.44718	139.8		
9	482	4.9	43.8	.824	40.2	30	1.45641	145.5		
10	527	6.7	50.5	.839	37.2	32	1.46604	153.8		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.8	52.3	.858	33.4	37	1.47437	156.1	40	10
12	437	5.5	57.8	.861	32.8	35	1.47680	157.4	42	20
13	482	6.0	63.8	.873	30.6	37	1.48390	161.2	52	40
14	527	4.3	68.1	.892	27.1	43			70	65
15	572	5.1	73.2	.908	24.3	48			115	80
Residuum		24.8	98.0	.982	12.6					

Carbon residue, Conradson: Residuum, 14.9 percent; crude, 4.3 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	10.7	0.692	73.0	
Total gasoline and naphtha	34.2	.743	58.9	
Kerosine distillate	9.6	.816	41.9	
Gas oil	15.6	.853	34.4	
Nonviscous lubricating distillate	9.6	.870-.903	31.1-25.2	50-100
Medium lubricating distillate	4.2	.903-.917	25.2-22.8	100-200
Viscous lubricating distillate				Above 200
Residuum	24.8	.982	12.6	
Distillation loss	2.0			

Bureau of Mines Laramie Laboratory
Sample PC-65-76

Item 18

IDENTIFICATION

Trading Bay field
Middle Ground Shoal sandstone-Tertiary
(Tyonek formation)
5,363-5,444 feet

Alaska
Seward Meridian
SW1/4NE1/4, sec. 4,
T 9 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.871 Gravity, ° API, 31.0 Pour point, ° F., below 5
Sulfur, percent, .05 Color, brownish black
Viscosity, Saybolt Universal at 100°F., 53 sec.; at 77°F., 66 sec. Nitrogen, percent, 0.149

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 82 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122	1.6	1.6	0.658	83.6					
2	167	2.4	4.0	.684	75.4	14	1.38214	123.7		
3	212	5.7	9.7	.731	62.1	27	1.40414	125.2		
4	257	5.8	15.5	.755	55.9	29	1.41734	128.1		
5	302	4.4	19.9	.775	51.1	31	1.42841	135.1		
6	347	4.4	24.3	.795	46.5	33	1.43878	141.0		
7	392	4.2	28.5	.815	42.1	37	1.44977	141.1		
8	437	4.2	32.7	.833	38.4	40	1.46007	147.5		
9	482	4.9	37.6	.846	35.8	41	1.46877	154.8		
10	527	7.8	45.4	.858	33.4	41	1.47706	161.1		
STAGE 2—Distillation continued at 40 mm. Hg										
11	392	1.5	46.9	.877	29.9	46	1.48476	164.7	42	5
12	437	5.0	51.9	.879	29.5	44	1.48692	166.2	45	10
13	482	5.6	57.5	.888	27.9	45	1.49244	170.4	55	30
14	527	4.7	62.2	.907	24.5	50			79	50
15	572	5.7	67.9	.918	22.6	53			140	70
Residuum		30.5	98.4	.983	12.5					

Carbon residue, Conradson: Residuum, 12.5 percent; crude, 4.3 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	9.7	0.707	68.6	
Total gasoline and naphtha	28.5	.757	55.4	
Kerosine distillate				
Gas oil	23.4	.857	33.6	
Nonviscous lubricating distillate	9.7	.883-.911	28.8-23.8	50-100
Medium lubricating distillate	6.3	.911-.924	23.8-21.6	100-200
Viscous lubricating distillate				Above 200
Residuum	30.5	.983	12.5	
Distillation loss	1.6			

Bureau of Mines Laramie Laboratory
Sample PC-67-80

Item 19

IDENTIFICATION

Trading Bay field
Hemlock conglomerate-Tertiary
10,500 feet (approximate)

Alaska
Seward Meridian
SE1/4SW1/4, sec. 26,
T 10 N, R 13 W

GENERAL CHARACTERISTICS

Gravity, specific, 0.864 Gravity, ° API, 32.3 Pour point, ° F., 20
Sulfur, percent, .11 Color, Brownish green
Viscosity, Saybolt Universal at 100° F., 45 sec; at 77° F., 53 sec. Nitrogen, percent, 0.026

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 760 mm. Hg
First drop, 131 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1	122									
2	167	1.0	1.0	0.706	68.9					
3	212	2.9	3.9	.711	67.5	17	1.39534	126.7		
4	257	5.3	9.2	.737	60.5	20	1.40764	127.4		
5	302	5.1	14.3	.754	56.2	21	1.41786	129.3		
6	347	5.8	20.1	.771	52.0	22	1.42756	134.0		
7	392	5.3	25.4	.788	48.1	24	1.43687	136.4		
8	437	5.6	31.0	.807	43.8	27	1.44619	138.1		
9	482	6.1	37.1	.823	40.4	30	1.45587	145.5		
10	527	7.9	45.0	.839	37.2	32	1.46582	153.2		

STAGE 2—Distillation continued at 40 mm. Hg

Fraction No.	Cut temp. ° F.	Percent	Sum, percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
11	392	4.8	49.8	.859	33.2	38	1.47613	152.0	38	25
12	437	6.7	56.5	.865	32.1	37	1.48003	157.5	44	35
13	482	5.7	62.2	.877	29.9	39	1.48757	160.2	52	45
14	527	5.3	67.5	.892	27.1	43			73	65
15	572	6.7	74.2	.903	25.2	46			125	90
Residuum	......	26.2	100.4	.984	12.3					

Carbon residue, Conradson: Residuum, 15.8 percent; crude, 4.7 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline	3.9	0.710	67.8	
Total gasoline and naphtha	25.4	.755	55.9	
Kerosine distillate	11.7	.815	42.1	
Gas oil	20.8	.855	34.0	
Nonviscous lubricating distillate	8.9	.874-.896	30.4-26.4	50-100
Medium lubricating distillate	7.4	.896-.909	26.4-24.2	100-200
Viscous lubricating distillate				Above 200
Residuum	26.2	.984	12.3	
Distillation loss				

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