ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 8672
4947 HRES HB 164 (FILE 2) (see ELF)

519

The Thomas Glossary of Oil Jargon

Glossary of Oil Industry Terms
(Alaskan Edition)

Ralph Thomas

☐ **Stable tax climate** — Any state/nation free of the socialist passion for gouging big industry. An effective arm-twisting term. The wise executive will use the old threat: "if you don't give us a 'stable tax climate,' we're going to take our $7 billion and invest it in hogs or hoola hoops or whatever."

☐ **Stable regulatory climate** — Any state/nation not controlled by fruitcakes only interested in things like clean water and clean air. Of course, the ultimate is no regulation at all. But, if regulation must be accepted, it is a job best left to the Boy Scouts.

☐ **Development Incentive** — Special tax/regulatory breaks given to the oil industry in exchange for the honor of the industry's presence.

☐ **Consumption** — The magic that makes the oil industry so much fun.

☐ **Finite Resource** — A foolish notion; often used in anti-industry propaganda. As it relates to oil, this theory has never been proven. Glory be, the oil keeps flowing.

☐ **Conservation** — Based on the "finite resource" sham. Some feel people should be urged, even forced, to conserve more and consume less. Conservation is as un-American as soccer, biathlons and solar panels.

☐ **Fair share** — A term used frequently by the socialists, who believe that just because oil is being extracted from beneath public land, the public should get a sizable chunk of the money. Fair share antics can wreak havoc on a stable tax climate.

☐ **Alaska Permanent Fund** — A bottomless pit of money where the fair-share crooks have taken all of the oil industry's money.

☐ **Permanent Fund Dividend** — A bribe paid annually by the fair-share crooks to each person in the state.

☐ **Hugh Malone, Ben Grussendorf, Alaska House** — Government sympathizers. Indian givers. Known to make proposals that would cut into oil industry profits. These men are dangerous.

☐ **Sen. Jan Faiks** — Industry boys like to call her "The Big Easy." But Jan prefers to be known as "Oil's Fairy Godmother." For a small price, this oilfield princess will swing a big bat for industry.

☐ **Alaska Senate** — "Easy Street." Also known as "Jan's Boys." A whole batch of low-priced, high-powered good buddies.

☐ **Local Hire** — The virtuous practice of hiring workers close to home (i.e. Houston, San Antonio, Tulsa, etc).

☐ **Marginal well** — Any oil well in North America. Only the Arabs have no marginal wells.

☐ **Economic Limit Factor** — A dandy of a tax break known as ELF. The ticket to a stable tax climate. (See development incentive)

☐ **Alaska** — A land where they still believe in ELFs.

RALPH THOMAS is managing editor of The Clarion.

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ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne		
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B In-value	(000 Bbl)	WHP	Exh B In-value	(000 Bbl)
81: 7	$22.7	$23.4	$22.1	47,116.1									
8	$22.7	$23.0	$22.0	47,124.2									
9	$22.0	$22.3	$21.4	45,765.4									
10	$22.0	$22.2	$21.4	46,917.3									
11	$22.1	$22.2	$21.4	45,997.6									
12	$21.8	$21.9	$21.2	46,763.3	$19.7	$19.3	1,091.5						
82: 1	$21.2	$21.5	$20.5	47,980.7	$19.7	$19.3	2,503.6						
2	$19.5	$20.1	$18.8	43,467.6	$19.6	$19.2	2,219.7						
3	$18.4	$18.8	$17.7	47,439.8	$18.0	$17.6	2,856.8						
4	$18.7	$19.0	$18.1	45,811.9	$17.7	$17.3	2,757.1						
5	$18.9	$19.0	$18.3	47,745.2	$17.9	$17.5	2,896.6						
6	$20.4	$20.9	$19.7	44,958.5	$17.9	$17.5	2,767.5						
7	$20.4	$21.0	$19.7	48,037.7	$17.8	$17.4	2,680.0						
8	$20.4	$21.0	$19.8	47,460.6	$17.9	$17.5	2,711.8						
9	$20.4	$20.9	$19.7	46,216.7	$17.7	$17.3	2,669.0						
10	$20.2	$20.7	$19.6	47,820.6	$18.0	$17.6	2,729.4						
11	$19.8	$20.1	$19.2	45,223.3	$18.5	$18.1	2,791.0						
12	$19.2	$19.4	$18.6	47,105.2	$18.0	$17.6	2,795.5						
83: 1	$18.3	$18.7	$17.6	48,244.5	$17.8	$17.4	3,197.0						
2	$17.4	$17.7	$16.8	43,167.5	$16.6	$16.2	2,838.7						
3	$17.3	$17.6	$16.7	48,504.2	$16.2	$15.8	3,017.4						
4	$17.3	$17.5	$16.6	46,543.9	$16.2	$15.8	2,966.8						
5	$17.3	$17.6	$16.7	45,955.5	$16.2	$15.8	3,394.0						
6	$17.4	$17.6	$16.7	45,365.2	$16.0	$15.6	3,239.7						
7	$17.5	$17.8	$16.8	47,456.5	$16.5	$16.1	3,671.3						
8	$17.8	$18.3	$17.1	47,305.9	$16.4	$16.0	3,282.6						
9	$17.8	$18.3	$17.1	46,681.0	$16.7	$16.3	3,426.8						
10	$17.7	$18.2	$17.1	48,382.2	$16.8	$16.4	3,310.9						
11	$17.6	$18.0	$16.9	45,952.7	$16.8	$16.4	3,686.7						
12	$17.7	$18.0	$17.0	47,231.7	$16.8	$16.4	3,828.9						
84: 1	$17.5	$17.8	$16.8	48,311.5	$16.7	$16.3	3,983.4						
2	$17.6	$18.0	$16.9	45,089.7	$16.6	$16.2	3,810.6						
3	$17.6	$18.0	$16.9	42,889.4	$16.6	$16.2	4,241.7						
4	$17.7	$18.1	$17.0	47,766.3	$16.2	$15.8	3,352.2						
5	$17.7	$18.1	$17.0	49,258.5	$16.6	$16.2	3,372.5						
6	$17.7	$18.1	$17.0	44,619.1	$16.7	$16.3	3,290.8						
7	$17.8	$18.2	$17.1	47,259.5	$17.0	$16.6	3,349.2						
8	$17.8	$18.2	$17.1	45,459.1	$16.6	$16.2	3,169.2						
9	$18.0	$18.4	$17.3	47,677.5	$16.9	$16.5	3,359.3						
10	$17.9	$18.3	$17.3	47,866.9	$16.9	$16.5	4,030.4						
11	$18.0	$18.2	$17.3	46,779.7	$17.1	$16.7	4,922.3						
12	$17.5	$17.6	$16.8	45,942.3	$16.8	$16.4	5,631.5						

ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne			
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)
85: 1	$17.0	$17.1	$16.3	43,993.1	$16.2	$15.8	5,297.2								
2	$16.7	$17.0	$16.0	45,234.2	$15.8	$15.4	5,753.8								
3	$16.8	$17.0	$16.1	49,430.0	$16.0	$15.6	6,581.1								
4	$16.9	$17.2	$16.2	45,448.6	$16.1	$15.7	6,438.7								
5	$16.9	$17.2	$16.2	50,053.1	$16.0	$15.6	6,771.3								
6	$17.0	$17.2	$16.3	48,340.8	$15.7	$15.3	6,380.7								
7	$16.8	$17.1	$16.1	47,943.0	$15.4	$15.0	6,724.5								
8	$16.8	$17.1	$16.1	47,064.3	$15.3	$14.9	7,240.0								
9	$16.9	$17.1	$16.2	47,552.9	$15.6	$15.2	7,132.7								
10	$16.9	$17.1	$16.2	48,576.0	$15.7	$15.3	7,255.1								
11	$16.9	$17.1	$16.2	45,883.5	$16.1	$15.7	6,429.4	$14.1	$14.3		205.5				
12	$17.6	$17.8	$16.9	48,428.9	$17.1	$16.7	6,794.4	$14.4	$14.7		498.4				
86: 1	$15.4	$16.2	$14.7	48,666.2	$15.7	$15.3	7,194.4	$12.6	$13.0		529.8				
2	$10.9	$11.9	$10.2	44,385.0	$9.5	$9.1	6,937.9	$8.3	$8.7		478.8				
3	$7.5	$7.8	$6.8	47,256.1	$5.4	$5.0	8,076.7	$4.0	$4.7		548.6				
4	$5.8	$6.1	$5.1	44,391.3	$4.1	$3.7	8,366.9	$4.5	$5.0		479.6				
5	$4.9	$5.1	$4.2	48,934.7	$4.3	$3.9	8,461.1	$2.5	$2.6		396.8				
6	$4.4	$4.6	$3.7	46,272.0	$4.5	$4.1	8,099.9								
7	$3.1	$3.4	$2.4	48,821.7	$2.8	$2.4	8,139.9								
8	$3.7	$4.2	$3.0	46,763.1	$3.4	$3.0	7,479.2					$3.7	$4.2	$3.0	175.8
9	$5.6	$5.7	$4.9	44,422.4	$5.5	$5.1	7,062.3					$5.6	$5.7	$4.9	7.3
10	$5.7	$5.8	$5.0	49,807.0	$5.3	$4.9	8,010.8					$5.7	$5.8	$5.0	118.4
11	$5.8	$5.9	$5.1	47,031.4	$5.5	$5.1	7,745.5					$5.8	$5.9	$5.1	298.7
12	$6.9	$7.3	$6.2	45,850.9	$6.6	$6.2	8,471.5					$6.9	$7.3	$6.2	675.0
87: 1	$8.8	$8.9	$8.1	51,824.3	$9.1	$8.7	9,261.9					$8.8	$8.9	$8.1	1,409.3
2	$9.8	$10.0	$9.1	42,605.7	$9.1	$8.7	8,037.5					$9.8	$10.0	$9.1	1,192.3
3	$10.0	$10.1	$9.3	50,474.3	$9.4	$9.0	9,196.7					$10.0	$10.1	$9.3	1,293.7
4	$10.8	$11.0	$10.1	49,711.5	$10.0	$9.6	8,767.3					$10.8	$11.0	$10.1	1,177.8
5	$11.0	$11.2	$10.3	51,031.9	$10.4	$10.0	9,030.6					$11.0	$11.2	$10.3	1,325.9
6	$11.6	$11.6	$10.9	46,381.1	$10.6	$10.2	8,806.2					$11.6	$11.6	$10.9	1,413.8
7	$12.2	$12.3	$11.5	48,170.9	$11.4	$11.0	8,340.7					$12.2	$12.3	$11.5	1,414.6
8	$12.5	$12.9	$11.8	49,775.7	$12.0	$11.6	8,131.8					$12.5	$12.9	$11.8	1,240.1

ELF ALTERNATIVES

DELAY ONLY

• $87 million new revenue available in FY 88 (30th percentile).

• Revenue rises gradually through 1992, then drops abruptly by $114 million when ELF again applies.

• Maintains Prudhoe tax at 15.0 percent.

• Kuparuk tax rate unchanged at 8.1 percent.

• No change in tax rates at Milne Point, Endicott, Lisburne, or other marginal fields.

• PEL adjustment unchanged. Falling oil prices could have magnified effect on severance tax revenue, i.e., 50 percent drop in wellhead price could produce 90 percent drop in revenue. State prohibited from asking for PEL adjustment if oil prices rise.

• Does not change provisions of current law allowing producers in large fields to gain tax rebates by adding wells producing at or near 300 barrels per day.

HOUSE SUBSTITUTE

• $94 million new revenue available in FY 88 (30th percentile).

• Revenue rises gradually through FY 93, then declines gradually.

• Prudhoe tax rate reduced to 14.8 percent.

• Kuparuk tax rate increased to 11.7 percent.

• Decreases tax rates for Milne Point, Endicott, Lisburne, and other marginal fields. Eliminates tax for all existing Cook Inlet oil fields.

• Reduces chance that PEL adjustment would magnify effect of falling prices on severance tax revenue. State is allowed to petition for upward PEL adjustment.

• Eliminates negative tax rates on incremental revenue, but retains incentives for incremental production

OMB/Division of Policy 5/14/87

Sean -
Greg Erickson points to p. 12 - Kuparuk has a negative tax rate for some wells under severity tax - Ned

OIL TAX QUIZ

MULTIPLE CHOICE:

1. How much profit does the oil industry make each day from North Slope oil and the pipeline?
   ___ A. The industry is making no profit on the Slope.
   ___ B. $800,000 per day.
   ___ C. $2,200,000 per day.
   ___ D. $6,200,000 per day.

2. How do state and industry shares of North Slope oil income compare?
   ___ A. State and local 80%/industry 5%/ feds 15%.
   ___ B. State and local 60%/industry 15%/feds15%.
   ___ C. State and local 45%/industry 35%/feds 20%.
   ___ D. State and local 35%/industry 45%/feds 20%.

3. How many new jobs has the oil industry created on the North Slope since the ELF became effective at Prudhoe Bay in June of 1987?
   ___ A. 2,400 jobs.
   ___ B. 800 jobs.
   ___ C. 200 jobs.
   ___ D. Oil industry jobs on the Slope appear to have declined.

4. Why did the state adopt the 1981 oil tax bill?
   ___ A. To give the oil industry a tax break.
   ___ B. Because the oil industry sued the state over its separate accounting corporate income tax law, putting over one billion dollars of state revenue at risk.
   ___ C. With the rise in oil prices, the state budget became so inflated that lawmakers wished to avoid the temptation posed by collecting the amount of oil taxes garnered under previous law.
   ___ D. Because separate accounting was viewed as an unfair and inequitable tax law.

5. What commitment did the state make to the oil industry in 1981?
   ___ A. No new taxes if the industry abandoned its lawsuit challenging the separate accounting law.
   ___ B. That the state would see them in court.
   ___ C. No deal was made, since no legislature can formally or informally bind a future legislature.
   ___ D. The legislature did not adopt the industry settlement proposal, and instead acted only to limit future liability.

6. What was the result of the oil industry's suit challenging the separate accounting law?
   ___ A. The industry won in the state trial court but lost on appeal to the state Supreme Court.
   ___ B. The industry lost in state trial court, won on appeal to the state Supreme Court but lost in the U.S. Supreme Court.
   ___ C. The industry lost in the state courts, but won in the U.S. Supreme Court.
   ___ D. The industry lost in the state trial court, the state Supreme Court, and the U.S. Supreme Court.

7. What did Commissioner of Revenue Williams (now Director of Tax Planning for Standard) tell the legislature would be the revenue effects of the 1981 tax bill?
   ___ A. A gain of $67 million from FY 82-87.
   ___ B. A loss of $141 million from FY 82-85 .
   ___ C. A loss of $711 million from FY 82-85 .
   ___ D. A loss of $1.001 billion from FY 82-87.

8. What were the revenue effects of the 1981 tax bill?
   ___ A. A gain of $67 million from FY 82-87.
   ___ B. A loss of $141 million from FY 82-85.
   ___ C. A loss of $711 million from FY 82-85.
   ___ D. A loss of $1.001 billion from FY 82-87.

TRUE OR FALSE:

9. Alaska has the highest effective severance tax rate in the U.S.

10. In 1981, oil industry officials said the state's share of North Slope oil income should be the same as the oil industry's.

11. Prudhoe Bay is the most profitable oil field in the nation.

12. According to ARCO, only $1.35 billion of $10.5 billion spent on Alaska oil development was actually spent in Alaska (from 1980-86).

13. For every dollar the oil industry collects in Alaska, the industry reinvests only 18¢ in Alaska.

(Answers on following page.)

Correct Answers:

1. D. This equals over $2 billion dollars per year. The figures are from *Petroleum Intelligence Weekly [PIW].*
2. D. These figures also come from *PIW.*
3. D. Between the fourth quarter of 1986 and the fourth quarter of 1987, oil and gas industry employment on the Slope as estimated by the Department of Labor declined.
4. B. A is incorrect because legislators and Governor Hammond believed the changes made by the 1981 law were largely revenue neutral. They rejected industry settlement proposals that would have required foregoing several hundred million dollars in revenue. D is incorrect because only the oil industry believed the tax was unfair. See the answer to question 6 for what happened in the courts.
5. B, C & D are all correct.
6. D. In addition, the trial court required the industry to pay legal costs of $1.5 million to the state for defending the industry's unsuccessful challenge.
7. B.
8. C & D are both correct.
9. False. If the oil fields in other states were transplanted to Alaska, most would pay no severance tax under either the present or proposed ELF. Currently, the effective severance tax rates in Wyoming and Louisiana are higher than Alaska.
10. True. Monte Taylor of Exxon and Richard Donaldson of Sohio made statements before the legislature expressing satisfaction with the idea of equal shares for the state and industry in testimony.
11. True.
12. True, according to figures in the January 1988 issue of ARCO's "On Top of ANWR."
13. True. During 1988 the industry is expected to collect $3.85 billion in cash flow from Alaska, and reinvest about $700 million.

Further information is available in the "The ELF: A Policy Perspective," an April 1988 briefing paper prepared by State of Alaska Division of Policy.

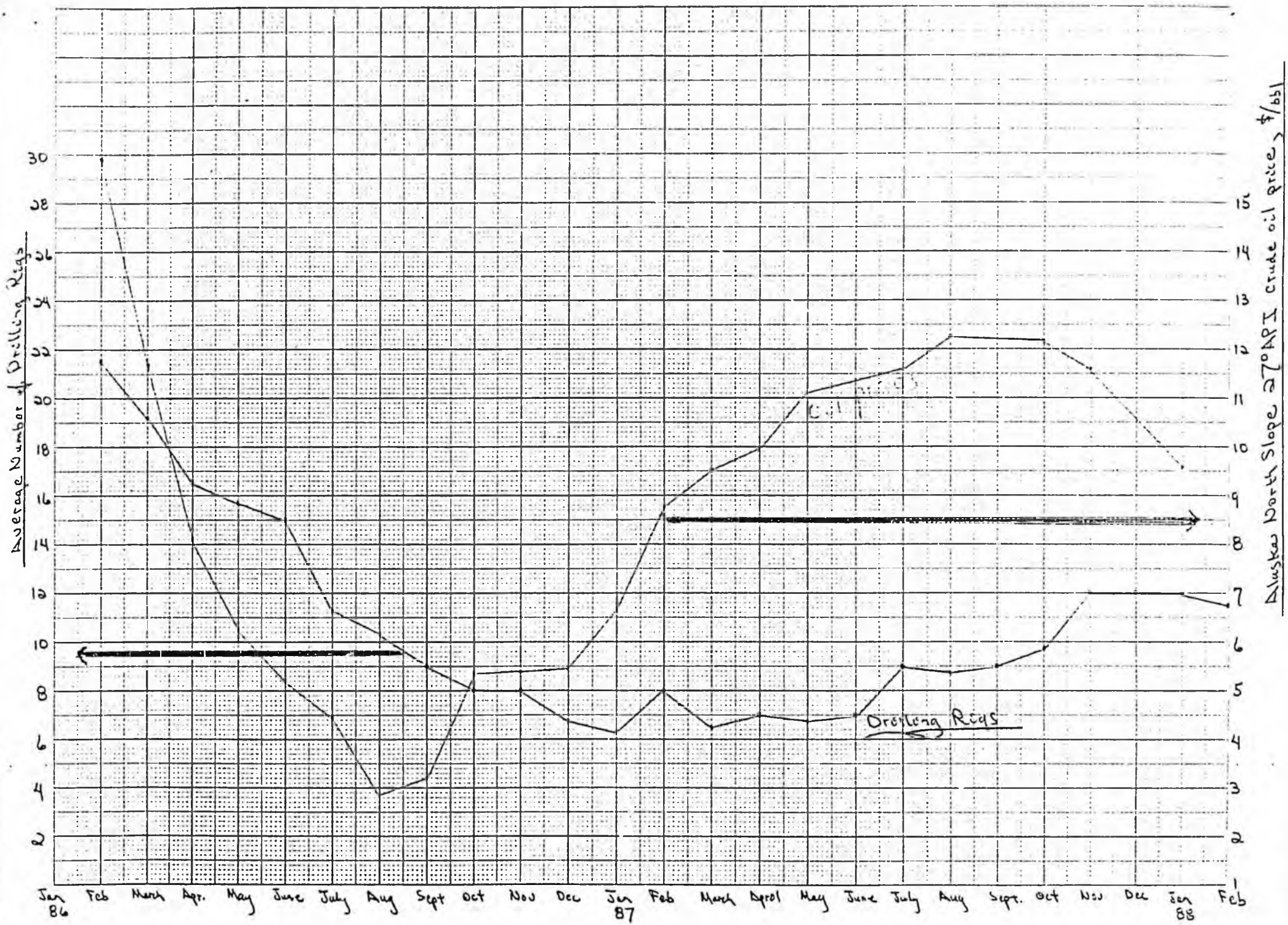
SAM

PIS count statewide dropped from 21 to about 6 - was about 12 last month

461510

Source: Oil & Gas Journal

Rig Count - Alaska



Hospital needs help

Kodiak Island Hospital Advisory Board, Administration, Medical Staff, and departmental employees make every effort to bring our community the level of health care it should have to meet a growing population and industry. For the past seven years, the question of upgrading the present facility to meet federal and state, as well as community requirements, has been studied with costs and ability to meet the future needs a prime consideration. Three outside firms specializing in these areas have assisted us in reaching the following decision. A new facility would not only be considerably more cost effective, but would greatly benefit the hospital in their mission to provide these services as projected over future years.

The hospital has worked its way up through the waiting list for state assistance to fund this building. We now find ourselves in a three way tie for this funding. We have met every pre-funding, preconstruction requirement and we are now ready to go to bid for construction. There is some doubt in our minds about the ability of the other two communities to begin construction this year. We are now told this has become a political decision and funding will be provided on the effectiveness of the community in convincing the legislature and state administration, through our legislators, we do need a new hospital. It would be a great help if both individuals and organizations in the community would take a moment to call our legislators office and express their support for funding for this needed public owned facility.

Sen. Fred Zharoff, 465-3473

Rep. Cliff Davidson, 465-2487

In addition to telephone calls, messages can be sent to our legislators through the Legislative Information Office in the Borough Building: 486-8116.

This is a time that your comments will count in keeping Kodiak equipped with the ability to render good health care.

Thank you for your help.

Wilton White

Sensible oil policy

By CLIFF DAVIDSON

All Alaskans own Prudhoe Bay, the largest and most prolific oil field in U.S. history. We have derived tremendous benefits from its development: the Permanent Fund, many municipal improvements such as schools, roads, harbors, and hospitals, as well as government services for children, the elderly and the disabled.

However, the public share of the revenue from this field is presently declining, while the major oil companies are increasing their share and proclaiming their profitability in a tough oil market. For this fiscal year, about $185 million has been directly transferred from our Alaskan treasury to the corporate treasuries of several major international oil companies through premature application of the so-called "ELF" tax break.

All over the state, people who need school improvements and municipal services wonder why the Legislature continues to allow a reduction in oil and gas taxes when our state revenues are in precipitous decline.

Part of the explanation is that the Legislature scheduled the tax break back in 1981, when oil prices were rising and it was thought that Prudhoe Bay would be in decline by 1987. Today it is clear that the industry will continue to operate, quite profitably, if the ELF is repealed. Yet, the State Senate has refused to act on an oil tax bill.

Governor Cowper and the House of Representatives have both

fields. Last year the Hou
nor's request, that did two
* prevented large tax b
Kuparuk, where tax incent
* provided a new tax
known field in Alaska, ir
Lisburne, and Milne Poi
cause it was uneconomic.

This approach makes
that Atlantic Richfield is
in the world – and guess
oil? From Kuparuk and P
essary for these oil fields.

The chief executive o
the company's profits are
has also publicly reporte
while reducing productio
tions of a company produ
ing economically.

Meanwhile, British Pe
of Standard Oil. Now it
98% of its oil production

And, Kuwait's nation
20% of BP. These aren't
the profitability and pote

Some industry repres
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the long-term productio
creased. Instead, we mig
oil and gas reserves.

Industry representativ
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oil and gas industry to in
to mention that there we
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the 1981 Legislature. A
"as for the possible rever
confidence in the ability
whatever is required to
wealth."

Clearly, the time has
tion. Today's legislators
our sagging economy,
district in the state needi
tals and a host of other
fund these worthy projec

Naturally, the oil in
changes benefit the indu
islature (in a time of oil
suit that questioned th
breaks. The Legislature
system. Since then, Al
worth of revenues that
system.

Alaskans have a cle
tax revenues that could
Or, shall we go ahead a
and will bring us back t

I strongly support G
tax break. I'm glad tha
gether on a tax syste
interests of all Alaska.

*(Cliff Davidson repr
member of the House R*

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BLOOM COUNTY

DAILY AVERAGE CRUDE OIL PRODUCTION PER PRODUCING OIL WELL

P.A.D. DISTRICT NUMBER IV
P.A.D. DISTRICT NUMBER V
UNITED STATES

(Barrels)

PRODUCTION PER WELL IS EVER DECREASING - PARTLY DUE TO ALASKA'S WELL-BASED E.L.F.?

Year	P.A.D. District Number IV					P.A.D. District V				
	Colorado	Montana	Utah	Wyoming	Weighted Average District IV	Alaska	California	Arizona, Nevada, Washington	Weighted Average District V	United States
1921	4	44	...	37	35	...	31	...	31	5
1922	4	47	...	42	41	...	42	...	42	5
1923	4	29	...	53	49	...	77	...	77	7
1924	14	21	...	42	38	...	55	...	55	7
1925	38	19	...	26	25	...	58	...	58	7
1926	62	25	...	21	23	...	54	...	54	7
1927	47	14	...	16	17	...	56	...	56	8
1928	38	10	...	17	16	...	59	...	59	8
1929	27	9	...	15	14	...	76	...	76	8
1930	21	6	...	14	12	...	66	...	66	7
1931	20	6	...	12	11	...	58	...	58	7
1932	16	5	...	12	10	...	55	...	55	7
1933	16	4	...	9	8	...	43	...	43	8
1934	16	7	...	10	9	...	41	...	41	7
1935	20	8	...	11	11	...	45	...	45	8
1936	24	11	...	12	12	...	48	...	48	9
1937	20	10	...	16	14	...	49	...	49	10
1938	20	9	...	16	13	...	49	...	49	9
1939	20	9	...	18	15	...	42	...	42	9
1940	17	10	...	20	17	...	40	...	40	10
1941	26	11	...	23	19	...	37	...	37	10
1942	35	10	...	31	22	...	36	...	36	9
1943	36	10	...	26	20	...	38	...	38	10
1944	43	11	...	24	20	...	40	...	40	11
1945	58	9	...	25	20	...	41	...	41	11
1946	84	9	...	26	23	...	38	...	38	11
1947	80	10	...	30	27	...	36	...	36	12
1948	67	8	...	32	26	...	35	...	35	13
1949	86	9	79	27	26	...	37	...	37	11
1950	84	7	102	32	27	...	31	...	31	12
1951	91	8	85	34	30	...	33	...	33	13
1952	85	8	78	38	33	...	32	...	32	13
1953	81	9	72	44	37	...	31	...	31	13
1954	73	10	64	45	37	...	29	10	29	12
1955	68	11	87	44	38	...	28	58	28	13
1956	74	15	61	44	40	...	26	58	26	13
1957	69	19	35	46	41	...	25	34	25	13
1958	60	21	124	47	45	...	24	51	24	12
1959	61	22	165	48	49	...	23	168	23	12
1960	64	24	136	49	49	...	22	300	22	12
1961	65	25	95	50	49	385	21	89	22	12
1962	59	23	104	42	43	540	21	33	21	12
1963	54	24	109	50	45	535	20	56	21	13
1964	50	21	83	48	43	560	20	58	21	13
1965	50	24	80	47	44	508	21	44	22	13
1966	54	27	76	44	43	690	23	60	24	14
1967	51	25	66	44	42	896	24	274	29	15
1968	48	40	72	44	45	1,010	25	355	30	16
1969	43	34	72	47	45	1,050	25	191	32	17
1970	38	33	70	46	44	1,423	25	[1]	29	19
1971	40	25	74	46	41	1,190	24	127	28	18
1972	48	29	81	43	43	1,011	24	130	26	19
1973	54	27	62	51	46	1,032	21	107	27	18
1974	50	31	88	44	46	848	22	85	26	18
1975	44	29	110	39	43	957	22	73	24	17
1976	45	27	79	32	39	912	20	67	32	16
1977	36	27	105	37	38	1,593	22	106	50	16
1978	31	25	66	38	36	3,358	21	139	48	17
1979	26	23	56	36	33	3,502	22	134	52	18
1980	23	22	48	34	31	2,518	21	132	56	17
1981	29	21	46	31	30	2,299	22	83	55	16
1982	27	20	39	28	27	2,231	23	72	58	15
1983	17	17	50	28	25	2,550	23	84	57	14
1984	15	19	53	29	26	2,691	23	85	58	14
1985	15	19	57	29	27	1,868	23	121	59	14
1986	15	19	58	28	26	1,683	25	159	67	14

[1] Data not available.

AUTHORITY: UNITED STATES DEPARTMENT OF ENERGY
"WORLD OIL"

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news

for release IMMEDIATELY

For further information contact
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ARCO ANNOUNCES EARNINGS

FOR FIRST QUARTER OF 1987

LOS ANGELES, Ca., April 23 -- ARCO today reported earnings of $239 million or $1.31 per share for the first quarter of 1987. Results for the same period a year ago were $299 million, or $1.64 per share.

Lodwrick M. Cook, chairman of the board and chief executive officer, said, "We are extremely pleased with our first quarter performance since we believe it demonstrates ARCO's earning power in a lower crude price environment. Although crude prices in the first quarter were below the first quarter of 1986, the effect on upstream earnings was almost entirely offset by lower exploration and operating costs. Crude oil prices have improved since the fourth quarter of last year, and we expect our performance to improve further as prices stabilize at today's levels."

ARCO's average price for domestic crude oil was $11.21 per barrel in the first quarter, compared with $14.14 per barrel in the same period last year. Average domestic natural gas prices fell to $1.64 per thousand cubic feet, versus $2.23 last year, and natural gas liquids prices averaged $9.97 per barrel, versus $12.40 in the 1986 first quarter.

First quarter earnings also included a $10 million net after-tax gain on the sale of certain Lower 48 oil and gas properties, after restructuring costs, as well as a $19 million after-tax gain related to the sale of a corporate asset. These were offset, however, by a $35 million after-tax charge related to the previously announced early redemption of certain debt issues.

-more-

Consolidated sales and other operating revenues for the first quarter of 1987 were $3,744 million, compared to $4,287 million for the same period a year ago.

After-tax earnings for worldwide oil and gas operations were $203 million in the first quarter of 1987 (including the $10 million net gain relating to the sale of Lower 48 producing properties), versus $202 million in the 1986 first quarter.

Exploration expenses totaled $75 million for the quarter, compared with $137 million in the same period last year.

Total production of crude oil and natural gas liquids averaged 740,600 barrels per day in the current first quarter versus 736,400 barrels per day a year ago. A decline in Lower 48 production due to property sales and natural field decline was more than offset by substantially higher Alaskan and international production. This included the first full quarter of production from the new Lisburne field, as well as increased production from Kuparuk.

Natural gas sales increased to 1,579 million cubic feet per day from 1,547 million cubic feet per day in the first quarter of 1986. The increase is attributable to higher foreign natural gas sales primarily from the start up in late 1986 of the Thames gas field in the North Sea. This was partially offset by a decline in Lower 48 fields as a result of property sales and reduced demand due to an unusually warm winter.

After-tax earnings from coal operations were essentially flat at $14 million versus $15 million last year.

"In our downstream operations, weaker margins for petroleum products reduced earnings for refining and marketing and integrated petroleum processing operations compared to last year's first quarter, when margins were particularly strong," said Cook. "However, on the positive side, ARCO Chemical Company had significantly higher earnings in the first quarter and all other operating segments continued their solidly profitable performances."

First quarter 1987 after-tax earnings from refining and marketing operations amounted to $25 million versus $90 million in the first quarter of 1986. The decline is primarily attributable to reduced margins brought about by a lag in the rise in product prices compared to crude price increases in the first quarter.

After-tax earnings from transportation operations were $86 million for the current quarter, compared with $87 million last year. The impact of the lower Trans Alaska Pipeline tariff was nearly offset by lower operating costs.

ARCO Chemical Company (intermediate chemicals and specialty products) had an outstanding performance in the first quarter. Volumes and margins improved for the Company's oxygenated products, resulting in after-tax earnings of $61 million, versus $26 million in the same period last year.

Lyondell Petrochemical Company (integrated petroleum processing) had after-tax earnings of $22 million compared with $32 million in the first quarter of 1986. Lower margins for refined products and petrochemicals were partially offset by $5 million of various nonrecurring items.

ARCO's annualized return on stockholders' equity was 18 percent in the first quarter of 1987, compared to 21.9 percent in the same period of 1986.

# # # #

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ARCO
FINANCIAL AND STATISTICAL DATA
(Millions of Dollars Except Per Share Amounts)

	Three Months Ended March 31, 1987	Three Months Ended March 31, 1986
Sales & other operating revenues (including excise taxes)	$3,744	$4,287
Income before income taxes	$ 397	$ 608
Provision for taxes on income	158	309
Net income	$ 239	$ 299
Income per share:		
Net income	$ 1.31	$ 1.64
After-tax segment earnings		
Resources:		
Oil and Gas	$ 203	$ 202
Coal	14	15
Products:		
Refining and Marketing	25	90
Transportation	86	87
Intermediate Chemicals & Specialty Products	61	26
Integrated Petroleum Processing	22	32
Unallocated expenses and other operations	(40)	(48)
Interest	(132)	(105)
Net income	$ 239	$ 299
Average common shares outstanding including equivalents (millions of shares)	183.0	182.2
Percent return on average shareholders' equity (annualized)	18.0%	21.9%

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ARCO Alaska, Inc.

news

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For further information
contact Susan Andrews, 265-6847

ARCO ANNOUNCES EARNINGS FOR THIRD QUARTER, NINE MONTHS

LOS ANGELES, Ca., October 26 -- ARCO reported net income of $315 million or $1.71 per share for the third quarter of 1987, an increase of 209 percent from the $102 million or $.56 per share earned in the third quarter of 1986.

Lodwrick M. Cook, chairman of the board and chief executive officer, said: "Crude oil prices were higher in the third quarter compared to a year ago, leading to significantly improved results from our oil and gas operations. Results also benefited from higher earnings from ARCO Chemical Company and higher crude oil and natural gas liquids production. These increases were partially offset by lower earnings from refining and marketing operations, resulting from significantly lower margins for petroleum products."

For the first nine months of 1987, net income was $884 million or $4.82 per share compared with $551 million or $3.03 per share in the same period of 1986.

Sales and other operating revenues totaled $4.4 billion for the third quarter of 1987, compared with $3.5 billion in 1986. For the nine month period, sales and other operating revenues amounted to $12.2 billion, versus $11.4 billion in the first nine months of 1986.

-more-

After-tax earnings for worldwide oil and gas exploration and production operations rose to $235 million in the current third quarter compared to $41 million in the same period last year. The improved results are primarily attributable to higher crude oil and natural gas liquids prices, along with higher production volumes.

ARCO's average price for domestic crude oil was $14.02 per barrel in the third quarter, compared with $7.04 per barrel in the third quarter of 1986. Average domestic natural gas liquids prices were $11.11 per barrel versus $7.75 per barrel in the 1986 third quarter. Average domestic natural gas prices were $1.61 per thousand cubic feet versus $1.67 per thousand cubic feet in the same period last year.

Worldwide production of crude oil and natural gas liquids averaged 728,700 barrels per day in the current third quarter versus 715,200 barrels per day a year ago. The increase was due to higher production from the North Slope of Alaska, partially offset by lower production from the Lower 48.

Average domestic natural gas sales were relatively flat at 1,147 million cubic feet per day versus 1,124 million cubic feet per day in the third quarter of 1986. Foreign gas sales averaged 79 million cubic feet per day compared to 89 million cubic feet per day last year. Higher U.K. production associated with the start-up of the Thames field in the fourth quarter of 1986 was more than offset by lower production from Indonesia and the

Netherlands.

Worldwide exploration expenses amounted to $96 million for the quarter, compared with $[illegible]0 million in the same period last year.

Coal operations reported after-tax earnings of $18 million in the third quarter of 1987 versus $32 million in the third quarter of 1986. The 1986 results included an after-tax gain of approximately $15 million for the sale of the company's interest in an Indonesian coal venture.

After-tax earnings for refining and marketing operations declined to $30 million in the third quarter of 1987 from $94 million last year due primarily to lower margins for petroleum products caused by a lag in the rise of product prices compared to crude prices.

After tax earnings for transportation operations were up slightly to $87 million from $84 million last year.

The intermediate chemicals and specialty products segment had a strong performance in the third quarter due primarily to higher margins for styrene. This segment reported after-tax earnings of $73 million versus a loss of $7 million in the third quarter of 1986, when results included a $44 million after-tax charge associated with the sale of certain chemical assets.

After-tax earnings for Lyondell Petrochemical Company (integrated petroleum processing operations) amounted to $23 million in the current third quarter versus $24 million in the same period last year. Margins for refined products fell sharply,

but this was nearly offset by higher margins and volumes for petrochemical products.

After-tax interest expense declined slightly to $125 million from $129 million in last year's third quarter as a result of lower debt levels offset by lower capitalized interest.

ARCO's annualized return on stockholders' equity for the first nine months of 1987 was 21.4 percent, compared with 13.6 percent a year ago.

# # # #

ATLANTIC RICHFIELD COMPANY
FINANCIAL STATISTICAL DATA
(Millions of Dollars Except Per Share Amounts)

	THREE-MONTHS ENDED SEPTEMBER 30		NINE-MONTHS ENDED SEPTEMBER 30	
	1987	1986	1987	1986
Sales & other operating revenues (including excise taxes)	$ 4,397	$ 3,532	$12,244	$11,368
Income before income taxes	571	222	1,568	1,120
Provision for taxes on income	256	120	684	569
Net income	$ 315	$ 102	$ 884	$ 551
Earned per share	$ 1.71	$ 0.56	$ 4.82	$ 3.03
After-tax segment earnings				
Resources:				
Oil and gas	$ 235	$ 41	$ 681	$ 242
Coal	18	32	50	62
Products:				
Refining and marketing	30	9	100	305
Transportation	87	84	256	262
Intermediate chemicals & specialty products (including ARCO Chemical Company)	73	(7)	204	60
Integrated petroleum processing (Lyondell Petrochemical Company)	23	24	76	112
Unallocated expenses and other operations	(26)	(37)	(99)	(132)
Interest	(125)	(129)	(384)	(360)
Net income	$ 315	$ 102	$ 884	$ 551
Percentage return on average stockholders' equity (annualized)	22.2%	7.6%	21.4%	13.6%
Average common shares outstanding including equivalents (millions of shares)	183.6	182.2	183.3	182.1

10/22/87

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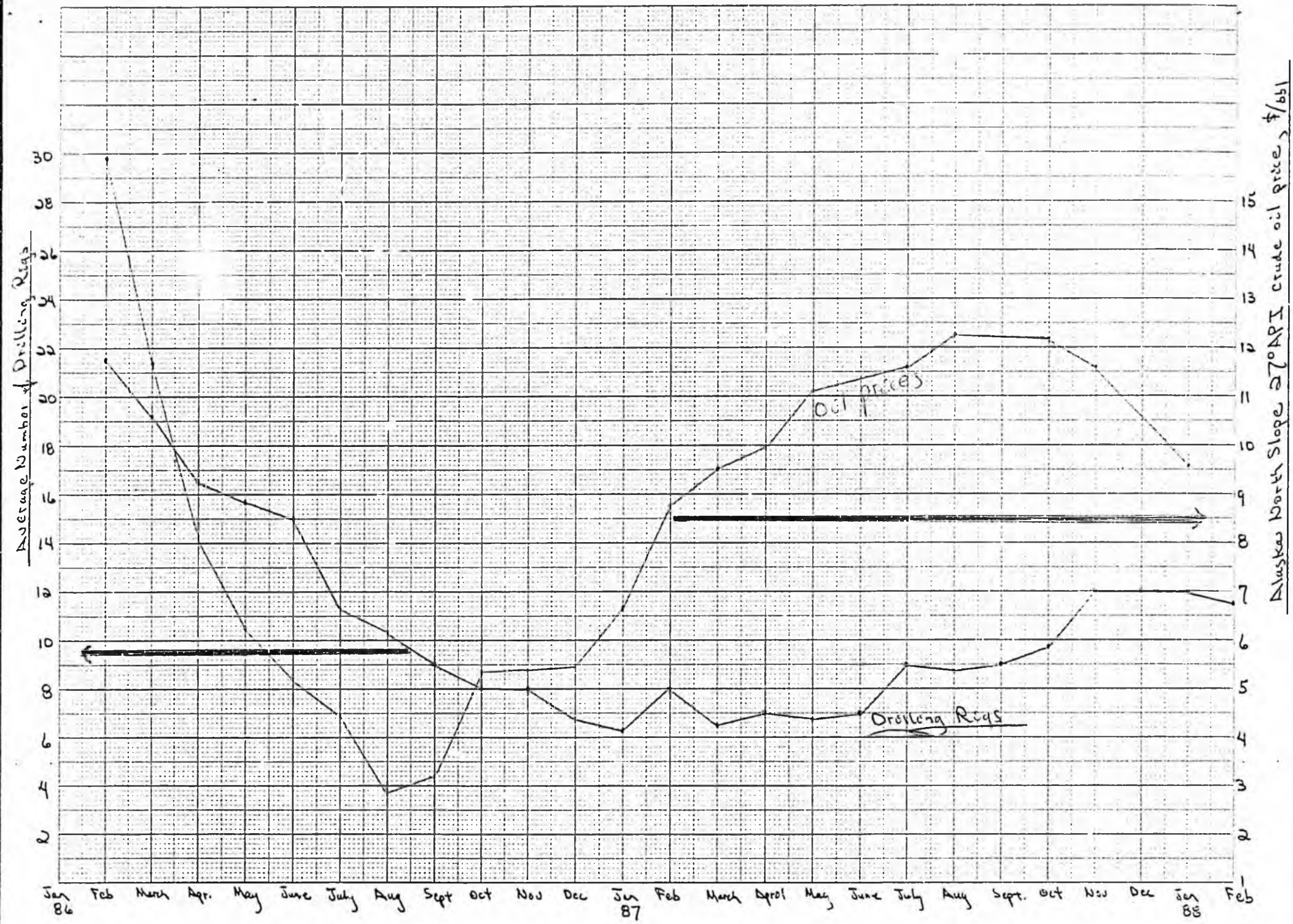
Source: Oil & Gas Journal

Reg Count - Alaska



ALASKA REPORT

Vol. 33, No. 46
11-18-87

Texaco, Arco, Standard Set Drilling Plans for 1988

DRILLING PLANS being made now will increase the active rig count in Alaska next year as Texaco Inc, Arco Alaska and Standard Alaska Production plan increased drilling activity for 1988.

Texaco has filed plans with the state indicating that it will drill up to three exploratory wells south of Kuparuk River field near Oliktok next year. Plans call for construction of an ice road and drilling pad to begin later this month and the first well, the Wolfbutton #1, to be spudded in early January.

Following completion of drilling at the first location, construction would then begin on a second ice road and the second and third wells would then be spudded simultaneously toward the end of February.

Texaco said drilling operations at the second and third wells would be completed in April and the sites demobilized by May 15. To date, contracts for the drilling rigs for the wells have not been awarded.

Arco Alaska also plans to drill an exploratory well on the North Slope next year and has dubbed the well the Prudhoe Pipeline #1. The company plans to drill the well at a location about 25 miles south of Deadhorse and has contracted Doyon Drilling's Rig #9 for the work.

Standard Alaska Production currently is reviewing bid proposals for two drilling rigs the company plans to use to drill an unspecified number of wells for the Eileen/West End project on the west side of Prudhoe Bay field. The development wells will be drilled into the Sadlerochit formation to produce an estimated 110 million bbls of crude from about 500 million bbls in place. The drilling is designed to produce oil partially cut off from the main Prudhoe Bay field reservoir by geologic formations.

Standard originally had planned to begin drilling there early this year, but slumping oil prices put the project on hold. Now, with oil prices in the $18-$20 range, Standard plans to begin drilling early next year and begin production next summer. Drillsites already have been built and the drilling contracts are expected to be awarded next month.

Current exploratory activity in the state has Tenneco Oil drilling its Aurora well in the Beaufort Sea off the coast of the Arctic National Wildlife Refuge. No information on the well is available as Tenneco has labeled the well "an extremely tight hole."

In North Slope development work, Standard Alaska is drilling at 13,160 ft at the P-24 and setting a cement plug at 14,640 ft at the K-33, both in Endicott field.

In Prudhoe Bay field, crews are setting a cement plug at an unspecified depth at Standard's K-10, while bad weather has hampered efforts to move Alaska United Drilling's Rig #2 to the new E-23 location following the completion of drilling activity at the E-27 last week.

Arco Alaska is drilling at 9,570 ft at the 3H-3 in Kuparuk River field and has sidetracked the hole at 7,100 ft at the DS 18-13 in Lisburne field. Drilling at the latter site has reached the 7,984-ft mark. In Lisburne field, crews are testing the blowout preventer at Arco's L2-8 prior to setting casing at 11,503 ft.

In Cook Inlet, Amoco Production is setting casing at 3,525 ft at the GP37 on the Anna platform, while Marathon Oil is cleaning cement out of seven-inch liner set at 11,748 ft and is preparing to complete the M-25 drilled from the Steelhead platform.

Onshore on the Kenai Peninsula, Unocal is continuing testing operations at the Cannery Loop #4.

Petroleum Information

a company of
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EXHIBIT E—1

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS OUTSIDE THE INITIAL PARTICIPATING AREAS PRUDHOE BAY UNIT AGREEMENT STATE OF ALASKA

Lands within the Unit Area that are not in the initial Participating Areas shall be developed and operated pursuant to the Plan of Development and Operations ("the Plan") described herein, to wit:

A. Hydrocarbon-productive Reservoirs have been discovered within the Unit Area in the Lisburne, North Prudhoe Bay (Permo-Triassic) and Kuparuk River formations, and these Reservoirs extend to lands in the Unit Area beyond the initial Participating Areas. As of the effective date of this Unit, these Reservoirs have not been reasonably proven to be capable of producing unitized substances in sufficient quantities to justify Working Interest Owners in developing and producing them. However, additional wells and studies are planned from 1977 through 1982 to further evaluate these Reservoirs prior to the formation of Participating Areas. The Plan for these other reservoirs include plans for the drilling of additional wells both within and outside the boundaries of the initial Participating Areas. Further, any well drilled on any part of a lease, any portion of which lease is included in the Unit Area, shall be deemed a well drilled in satisfaction of this Exhibit E-1 regardless of whether or not such well is located in the Unit Area; provided, that it is shown to the satisfaction of the Director that the bottom-hole target of the well will provide a reasonable geologic test or geologic information significant to Unit Operations.

1. *Lisburne Reservoir.*

a. *Work in Progress.* Three Lisburne test wells (A.R.Co./Exxon Gull Island 2; BP Sag Delta 35-12-16; and BP Sag Delta 10-11-16) were commenced in January 1977, and drilling operations in connection therewith should be completed by the end of 1977.

b. *Studies.* For the period January 1, 1978 to July 1, 1982, detailed geological, geophysical, and engineering studies

will be carried out by each affected Working Interest Owner to evaluate the structure, areal distribution, and continuity of hydrocarbon-bearing reservoirs, as well as the productive capability of such reservoirs within the Lisburne carbonate section. Based on these studies, the economic feasibility of further Lisburne Reservoir(s) development will be determined.

c. *Further Drilling.* For the period January 1, 1978 to July 1, 1982, Working Interest Owners plan to drill three (3) wells in addition to the above for further appraisal and delineation of the Lisburne Reservoir(s). Since the location of such wells will, in part, be dependent upon the results of the Lisburne wells described in paragraph (a) above, and some of the studies described in paragraph (b) above, the locations are undesignated at this time.

2. *Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs.*

a. *Wells.* Two undesignated wells are planned to evaluate the Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs prior to July 1, 1982.

b. *Studies.* Prior to July 1, 1982, technical studies including detailed Kuparuk stratigraphy and lithofacies work, and combined geological-geophysical structural analysis for the Kuparuk and North Prudhoe Bay (Permo-Triassic) Reservoirs are planned. Based on these studies, the economic feasibility of further development will be determined.

At least two of the wells described in paragraph (1.c) and (2.a) hereof are planned to be drilled prior to July 1, 1981.

The terms of this Plan shall cover the time period from the Effective Date of the Prudhoe Bay Unit Agreement through June 30, 1982.

Unit Operators will continue to obtain approvals and permits for Unit Operations as required by State laws, regulations and/or State Oil and Gas Lease Stipulation (Attachment No. 1 hereto).

Commencing July 1, 1978, and each year thereafter, Unit Operators will file progress reports describing operations under this Plan for the preceding twelve (12) month period.

ATTACHMENT NO. 1 TO EXHIBIT E-1

OIL AND GAS LEASE STIPULATION

I. Prior to commencement of any operations on the lease, the lessee shall obtain written approval from the Director, Division of Lands for the location of all operations and type of facilities in order to protect fish and wildlife, prevent pollution, and minimize surface damage. This stipulation does not affect the requirement that the lessee obtain approval of the Alaska Oil and Gas Conservation Committee pursuant to AS 31 and the regulations adopted thereunder.

The lessee shall:

(a) Submit, in triplicate, at least 30 days prior to beginning any operations on this lease, to the Director, Division of Lands, a plan of operation that will include statements, maps, or drawings relating to:

(1) The methods to be used to assure proper disposal of mud, oily waste, garbage, refuse, and other pollutants.

(2) The design of pollution prevention facilities.

(3) The location of any proposed well or wells, buildings, rights-of-way, airstrips, and storage facilities.

(4) The location and design of material sites.

(5) Measures to be taken to prevent erosion (particularly of roads and material sites) and damage to watersheds and vegetation.

(6) The location of proposed seismic activities.

(b) Keep the operational plan current in all respects.

II. The lessee shall:

(a) Comply with the provisions of the approval and do all things reasonably necessary to prevent or reduce to the fullest extent scarring and erosion of the lands, pollution of the water resources, and damage to the watershed. Should activities of the lessee cause damage to the watershed or pollute the water resource, the lessee agrees to repair such damage in a manner acceptable to the Director.

(b) Allow authorized personnel of the Department of Natural Resources and the Department of Fish and Game to enter the premises to inspect the installations and operation activities of the lessee.

(c) Prior to the beginning of operations, appoint and maintain, at all times during the term of the lease, a local agent upon whom may be served written orders or notices respecting matters contained in these stipulations and to inform the authorized officer in writing of the name and address of such agent. If a substitute agent is appointed, the lessee shall immediately inform the said representative.

III. The lessee shall not deviate substantially from the approved plan of operation until revision or amendments of the plan are approved in writing, or abandon any site, approval for which is required herein, until final cleanup and revegetation, if required, is approved in writing by the authorized officer as provided herein.

IV. Should the lessee believe that compliance with any of the provisions of approval is unnecessary, he may request a waiver thereof by letter to the appropriate authorized officer stating why a waiver should be considered.

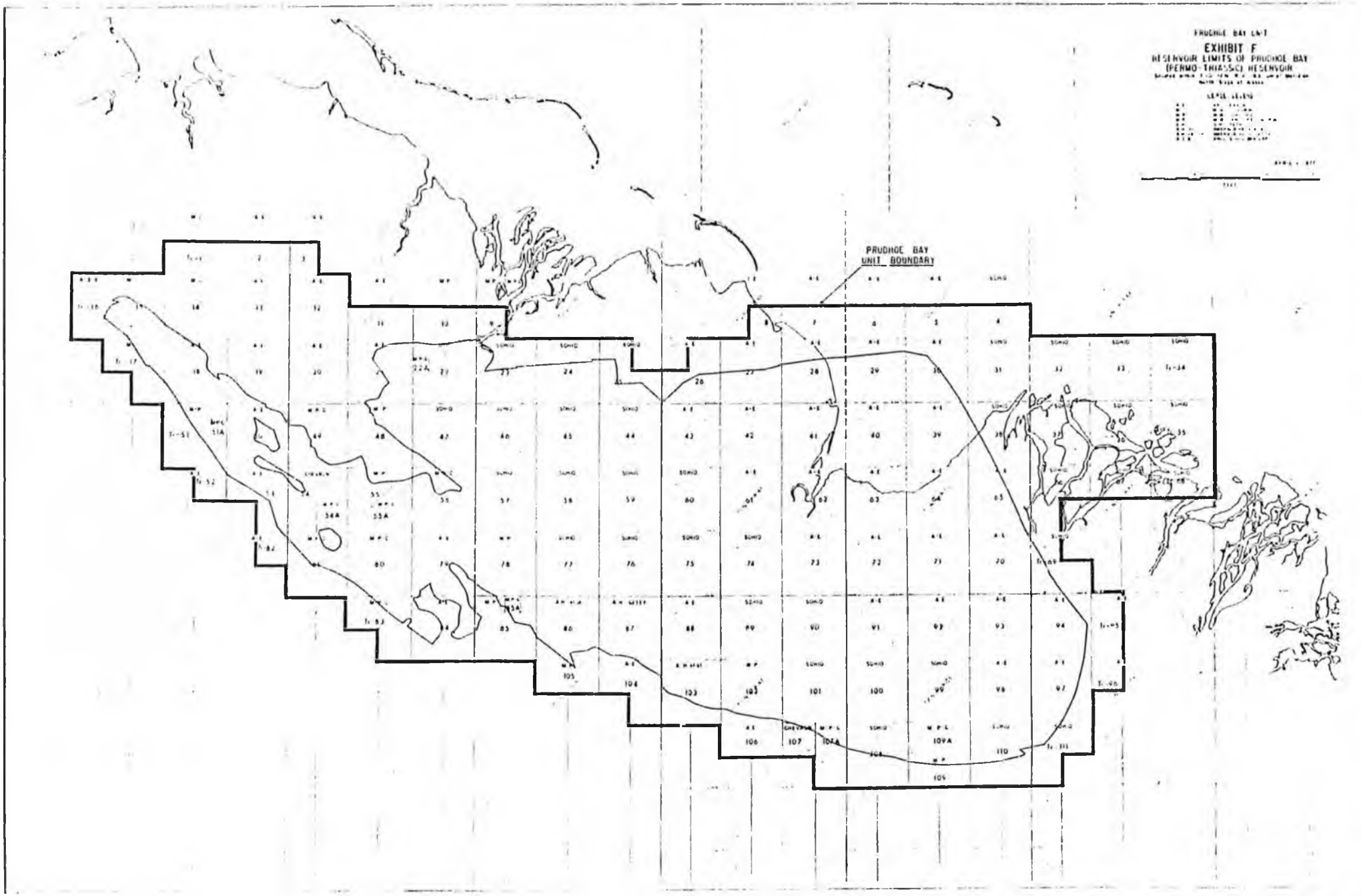

PRUDHOE BAY UNIT
EXHIBIT F
RESERVOIR LIMITS OF PRUDHOE BAY (PERMO-TRIASSIC) RESERVOIR
PRUDHOE BAY UNIT BOUNDARY

EXHIBIT E

PLAN OF DEVELOPMENT AND OPERATION PRUDHOE BAY (PERMO-TRIASSIC) RESERVOIR PRUDHOE BAY UNIT AGREEMENT STATE OF ALASKA

The Plan of Development and Operations ("the Plan") for the Gas Cap and Oil Rim Participating Areas within the Unit has been formulated to achieve maximum economic recovery of oil and gas consistent with good conservation, sound engineering practice and the correlative rights of the Working Interest Owners.

This Exhibit outlines the Plan which the Working Interest Owners have adopted to develop the Unitized Substances of the Initial Participating Areas in as prudent and expeditious a manner as possible. Fundamental to this Plan has been the assessment of reservoir productivity, facility capability, and the time required to finance, design, fabricate, and install the necessary production and transportation facilities.

This Plan summarizes both the short and longer term reservoir management considerations and describes the facilities which will be utilized therein. Detailed technical justification for the Plan is contained in a report entitled "Technical Considerations Prudhoe Bay Unit Operating Plan, North Slope—Alaska." This report was forwarded to the Director, Division of Energy and Minerals Management, Department of Natural Resources, State of Alaska, on October 20, 1976.

Short-Term Plans

The short-term aspects of the Plan cover initial oil and gas off-takes, gas injection, produced water disposal, and development drilling. Early ratification of this Plan is needed to enable Working Interest Owners, and other parties associated with financing and installing production and transportation facilities, to proceed on schedule.

Oil production is anticipated to begin in mid-1977. Production facilities to support an average oil offtake of 1.2 MMB/D will be

completed by January 1978. Well and facility additions are planned during 1978 and 1979 to increase the average oil offtake to 1.5 MMB D. plus condensate production, when pipeline capacity is available.

Injection facilities will be installed for the re-injection of gas produced in excess of that needed for fuel and sales. Initially this injection capacity will be 1.2 BCF D but will be increased to approximately 2 BCF D by mid-1979.

It is planned to commence gas pipeline deliveries of 2 BCF/D as soon as a pipeline and plant to condition the gas to specification can be completed. This is currently estimated to be about five (5) years after the start of oil production. Studies have shown that the Prudhoe Bay (Permo-Triassic) Reservoir could be managed so that the planned deliveries would not affect ultimate oil recovery. Depending upon the reservoir performance, it might be possible to increase gas deliveries to 2.5 BCF D.

Water production will be minimal initially and will be disposed of by injection into shallower Tertiary Cretaceous sands which are separate from the Permo-Triassic sands. When the produced water becomes significant it will be re-injected into the Sadlerochit formation.

Development drilling to date has been based on two wells per section. Near term plans include drilling selected wells on 160-acre spacing from existing drill sites during 1977.

Initial development within the Prudhoe Bay (Permo-Triassic) Reservoir will be in the Main Area Sadlerochit Formation. Development of the Eileen Area and other Permo-Triassic formations will be phased into the overall Plan so as to maximize the efficiency of the continuing development plan and to maintain field production.

Longer Term Plans

The Working Interest Owners have conducted extensive reservoir performance studies. The results of these studies combined with engineering judgment developed from experience in other fields have led to development of the long-term reservoir management plans.

In the longer term, the scope of the operation may ultimately include the implementation of a number of measures such as:

(a) the drilling of wells on one hundred sixty (160) acre spacing, closer if warranted;

(b) the working over of wells to limit undesirable gas and water production;

(c) the installation of additional gathering and separation facilities to accommodate rising gas-oil and water-oil ratios, including low pressure systems when necessary;

(d) the installation of artificial lift in wells;

(e) the injection of source water where appropriate.

These measures, viewed in conjunction with their possible scale and timing, collectively offer a degree of flexibility which is necessary for the successful management of the energy resources within the Prudhoe Bay (Permo-Triassic) Reservoir.

It is anticipated that with the additional drilling and installation of facilities it will be possible to sustain the planned oil offtakes for approximately eight years before production begins declining. Such development could ultimately require five hundred (500) or more wells on one hundred sixty (160) acre spacing. Futher development drilling to less than one hundred sixty (160) acres per well might be justified in selected areas.

It is planned to selectively inject produced water into the Sadlerochit Formation in areas of low natural depletion when volumes become significant. Thus, through redistribution by re-injection, the benefits of natural water influx will be maximized.

It is planned to supplement the injection of produced water with source water injection when predictions of additional recovery can be verified and the economic viability of the project can be substantiated. Reservoir performance and testing are necessary before this project can be engineered to assure successful implementation. Studies by the Working Interest Owners indicate that source water injection is mechanically feasible, but additional studies will be required to optimize the waterflood facility design. Although source water injection plans cannot be finalized, design and implementation

studies will proceed concurrently with field testing and data gathering, so as to reduce the time from final decision to implementation to approximately three years.

Over the life of the Prudhoe Bay (Permo-Triassic) Reservoir the Plan will undergo continued evaluation and modification in the light of observed performance. A very important aspect of this continuous review process will be an active program of reservoir surveillance and testing. Provisions exist within the Plan to monitor intensively gas-oil and water-oil contact movements, reservoir pressures and the performance of individual wells. Preliminary water injectivity tests are also planned to determine injectivity into various subzones of the reservoir and to evaluate water displacement characteristics in the reservoir. The Tertiary/Cretaceous sands overlying the Sadlerochit formation constitute a possible source of test injection water.

Drilling and Facility Plans

The development drilling and production facility plans outlined below are consistent with the objectives of the Plan for the field. The well spacing for this Plan provides flexibility to drill future producing wells and water injection wells as required. Modular construction and the physical layout of the existing production facilities provide maximum flexibility for future additions and expansions.

A multi-rig program will be in operation during 1977 through 1981 and beyond to provide additional wells. The bottom-hole locations of existing development wells and possible locations for future wells on 160-acre spacing are presented in Figure 1. This coverage includes those areas of the Prudhoe Bay (Permo-Triassic) Reservoir with an initial oil column in excess of one hundred (100) ft.

Producing wells are directionally drilled from strategically located drill site pads. These sites consist of gravel pads which insulate the underlying permafrost. Multiple-well drill pads permit concentration of surface facilities reducing required pipeline, road and power distribution networks. Existing drill pads will be extended and future drill pads will be installed as needed to accommodate the development drilling program. The surface locations of existing and possible future drill pads and drill sites are displayed on Figure 1.

Production from the wells in the Main Area will be processed at six field gathering centers flow stations. The first two are scheduled for production start-up during the second quarter of 1977. The third and fourth are scheduled for start-up during the third quarter of 1977. Scheduled start-up of the fifth and sixth will be mid-1978 and mid-1979, respectively. Total field gathering center flow station capacity will be 1.8 MMB D upon completion of all six facilities. This capacity allows the production offtake requirements for the field to be met with one center station completely shut down.

Initially there will be two flowline configurations which will transport the produced fluids from the wellheads to the field gathering centers flow stations. One configuration incorporates a separate flowline for each well, and the other will consist of common flowlines with well streams commingled at drill site manifolds. Additional flowlines will be needed in the future as development proceeds and additional wells are brought on production. Flowline configuration will depend on operating conditions at the time they are needed. Large diameter flowlines and manifolds are planned to offset the decline of wellhead flowing pressure. With further decline in wellhead flowing pressure, a reduction of first stage separator operating pressure is planned together with a possible expansion and relocation of first stage facilities at the drill pads and drill sites. Concurrently, low pressure compression at the field gathering centers flow stations may also be installed.

At each gathering center flow station the produced fluids will be separated into oil and condensate, gas, and water. Three-stage separation of produced fluids is planned. Well test facilities will be located at the gathering centers or the drillsites, dependent upon flowline configuration. The separator oil and condensate will be processed to pipeline specifications, and shipped through large diameter transit lines to the TAPS origin station. The separator gas will be compressed, conditioned as required, and sent through large diameter transit lines to the central gas compression plant located in the A.R.Co. operating area. Initially, all produced gas, excluding field fuel and fuel for TAPS, will be compressed at the central gas com-

pression plant and reinjected into the gas cap of the Sadlerochit reservoir. Ten (10) wells for initial gas injection purposes have been drilled from a pad just north of the central gas compression plant. If needed, additional gas injection wells will be drilled from a future pad to be located west of the central compression plant.

Some of the gas delivered to the central compression plant will supply the field fuel gas unit. This is located adjacent to the central compression plant and is designed to furnish up to 100 MMCF D of conditioned gas for use as fuel in field operations and TAPS pump stations.

Future additions to the produced gas system include a plant to condition gas for sales. With the commencement of gas sales, the gas will be routed to the gas conditioning plant for the removal of carbon dioxide and gas liquids for dewpoint control. Tentative plans are to transport some of the gas plant liquids that are extracted to the oil gathering system for delivery to TAPS with the remainder being used for fuel. Processed gas will be returned to the sales boost compression plant for required compression and transport to the sales gas pipeline.

Produced water will be treated, filtered, and injected initially into water disposal wells completed in the shallower Tertiary/Cretaceous sands at locations near the field gathering centers flow stations. Six such wells presently exist at the gathering centers flow stations. Facilities to reinject up to 200 MB D of produced water will be available and will be augmented as necessary. It is expected that such facilities might be expanded to handle up to 500 MB/D of produced water.

Electrical power for the field is supplied by the central power station located in the BPA operating area. Power generation is by gas turbine. The power is transmitted to the two operating areas by an overhead 69 KV transmission line and supplies the electrical requirements of the various production facilities.

Development of the West End (Eileen Area) of the field is to be phased in later into the overall Plan of Development, consistent with the most efficient production of the field. Additional study of the

well potentials and better definition of the West End will be required before this further development scheme can be finalized. It is expected that this information will be obtained over the next few years. Nevertheless, a tentative pattern of wells and pads corresponding in scope to the Main Area development has been shown on Figure 1.

Existing and possible future production facilities, pipelines, roads, bridges, airstrips, and base camps needed to support present and future field operations for the Main Area development and for the tentative Eileen Area development are shown on Figure 2.

An annual update of Figure 1 and Figure 2 will be submitted to the Director.

Unit Operators will continue to obtain approvals and permits for Unit Operations as required by State laws, regulations, and/or State Oil and Gas Lease stipulation (Attachment No. 1 hereto).

An annual progress report, summarizing the prior year's activities under this Plan, will be filed with the Director.

Attachment No. 1 to Exhibit E

OIL AND GAS LEASE STIPULATION

I. Prior to commencement of any operations on the lease, the lessee shall obtain written approval from the Director, Division of Lands for the location of all operations and type of facilities in order to protect fish and wildlife, prevent pollution, and minimize surface damage. This stipulation does not affect the requirement that the lessee obtain approval of the Alaska Oil and Gas Conservation Committee pursuant to AS 31 and the regulations adopted thereunder.

The lessee shall:

(a) Submit, in triplicate, at least 30 days prior to beginning any operations on this lease, to the Director, Division of Lands, a plan of operation that will include statements, maps, or drawings relating to:

(1) The methods to be used to assure proper disposal of mud, oily waste, garbage, refuse, and other pollutants.

(2) The design of pollution prevention facilities.

(3) The location of any proposed well or wells, buildings, rights-of-way, airstrips, and storage facilities.

(4) The location and design of material sites.

(5) Measures to be taken to prevent erosion (particularly of roads and material sites) and damage to watersheds and vegetation.

(6) The location of proposed seismic activities.

(b) Keep the operational plan current in all respects.

II. The lessee shall:

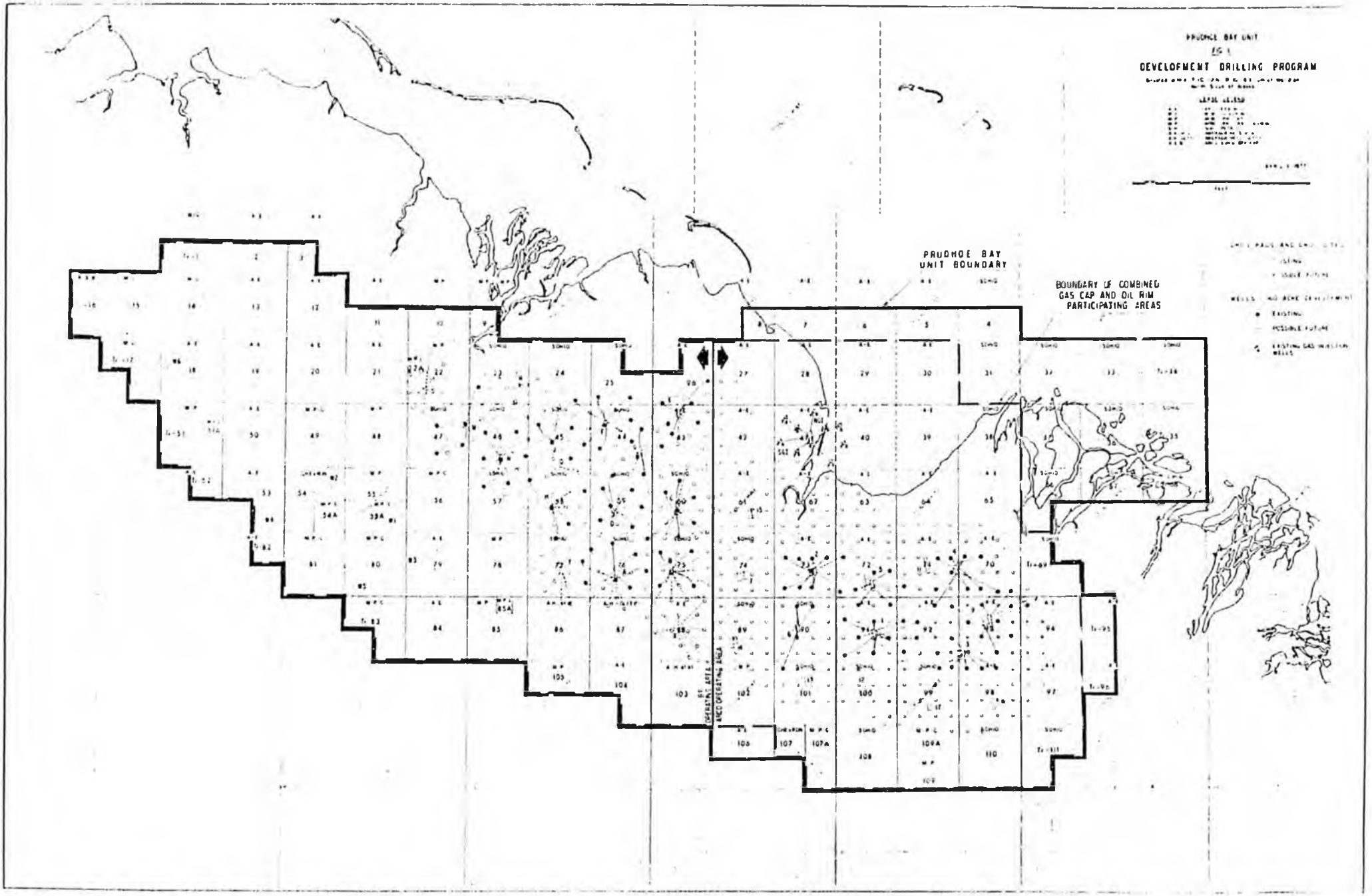
(a) Comply with the provisions of the approval and do all things reasonably necessary to prevent or reduce to the fullest extent scarring and erosion of the lands, pollution of the water resources, and damage to the watershed. Should activities of the lessee cause damage to the watershed or pollute the water resource, the lessee agrees to repair such damage in a manner acceptable to the Director.

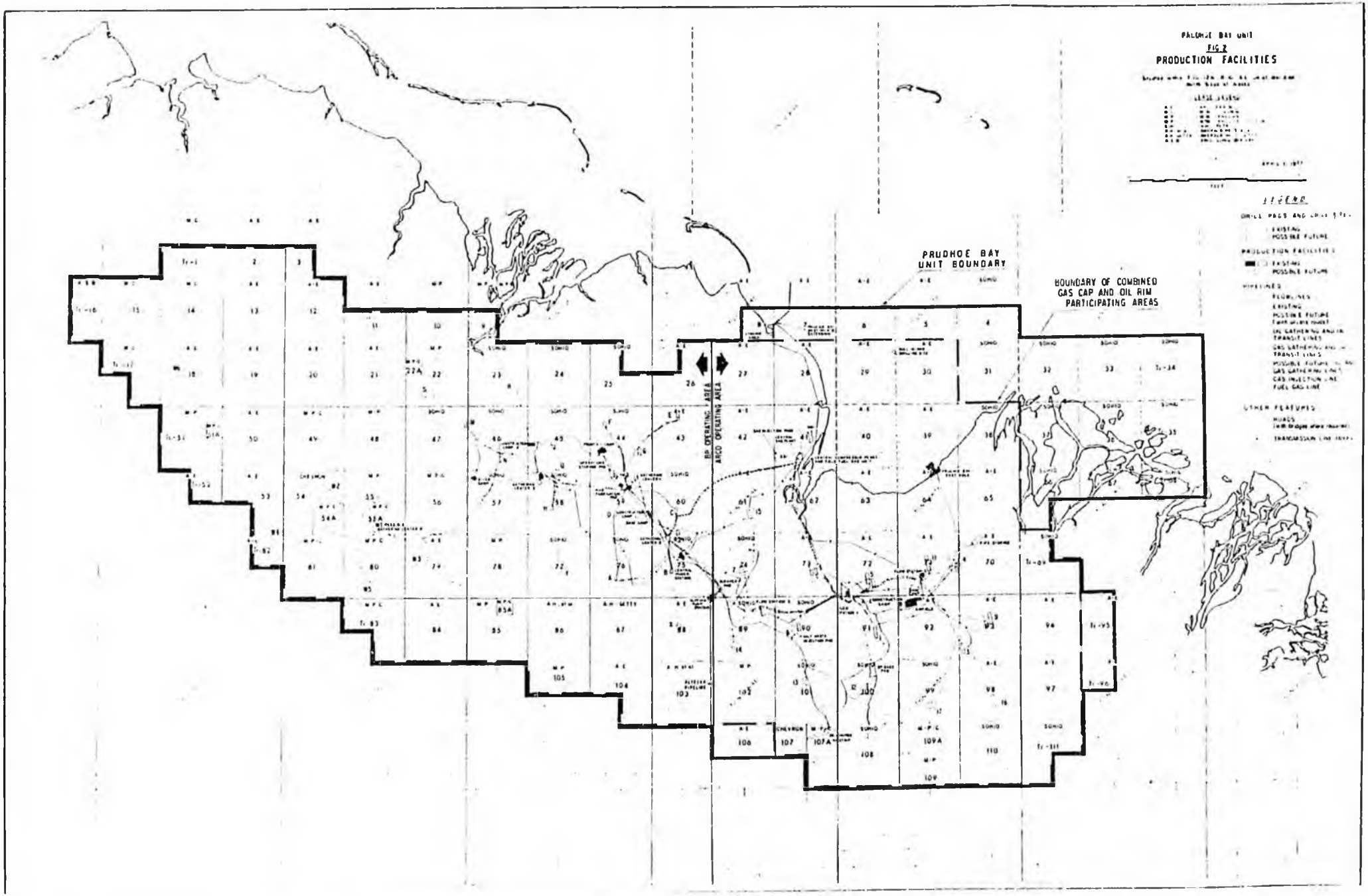
(b) Allow authorized personnel of the Department of Natural Resources and the Department of Fish and Game to enter the premises to inspect the installations and operation activities of the lessee.

(c) Prior to the beginning of operations, appoint and maintain, at all times during the term of the lease, a local agent upon whom may be served written orders or notices respecting matters contained in these stipulations and to inform the authorized officer in writing of the name and address of such agent. If a substitute agent is appointed, the lessee shall immediately inform the said representative.

III. The lessee shall not deviate substantially from the approved plan of operation until revision or amendments of the plan are approved in writing, or abandon any site, approval for which is required herein, until final cleanup and revegetation, if required, is approved in writing by the authorized officer as provided herein.

IV. Should the lessee believe that compliance with any of the provisions of approval is unnecessary, he may request a waiver thereof by letter to the appropriate authorized officer stating why a waiver should be considered.


PRUDHOE BAY UNIT
DEVELOPMENT DRILLING PROGRAM
PRUDHOE BAY UNIT BOUNDARY
BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS


PRUDHOE BAY UNIT
FIG 2
PRODUCTION FACILITIES
LEGEND
PRUDHOE BAY UNIT BOUNDARY
BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS
BP OPERATING AREA
ARCO OPERATING AREA

ARCO Alaska, Inc.
P. O. Box 360
Anchorage, Alaska 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, Alaska 99502

July 2, 1981

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
703 E. Northern Lights Boulevard
Anchorage, Alaska 99503

Subject: Prudhoe Bay Unit
Annual Progress Report

Dear Sir:

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

P. B. Norgaard
Vice President
ARCO Alaska, Inc.

P. J. Martin
Assistant General Manager
(Operations)
Sohio Alaska Petroleum Company

cr
Attachment

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the previous years' activities under the plan of development and operation, which is incorporated in the Unit Agreement as Exhibit 'E'.

Oil Production

Since June 1, 1980, production to the TAPS line has been essentially continuous, at approximately 1.5 MMSTB/D, with one three-week shortfall occurring in late April and early May, 1981. This shortfall was a result of planned maintenance activity at Gathering Center 1. During this period the field rate was maintained at 1.4 MMSTB/D. Otherwise, only brief interruptions to rate occurred during the past year. During the period of June 1, 1980 through May 31, 1981, a total of 551 MMB of oil and condensate was delivered to the pipeline at an average rate of 1509 MBPD. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1981 is 1763 MMB, including approximately 3.73 MMB to the crude oil topping plant.

Gas Production And Injection

Since June 1, 1980 through May 31, 1981, a total of 622 MMMSCF of gas has been produced from the field and 571 MMMSCF was reinjected into the

gas cap of the Prudhoe Oil Pool. The majority of the remaining 51 MMMSCF has been used as fuel, purge and pilot gas, with only a minor amount flared. The most significant flaring incident occurred during the Large Diameter Flow Line Test at Flow Station No. 2 in December, 1980, when approximately .22 MMMSCF was flared while testing C Train at low pressure. All flaring is being held to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil and Gas Conservation in Conservation Order No. 145-A of January 12, 1978.

Water Production

Water production during the past year has increased slightly. From June 1, 1980 through May 31, 1981, a total of 14 MMB of water was produced. Approximately 4.6 MMB of this total was produced intentionally from two Drill Site 1 wells in the Eastern Operating Area for produced water injectivity tests at Drill Site 5. The remainder was disposed of by injection into the Cretaceous/Tertiary sands through disposal wells located at each of the Flow Stations/Gathering Centers.

Additional Wells And Facilities

As of June 1, 1980, 244 oil wells were connected and capable of producing to the Flow Stations/Gathering Centers. An additional 40 wells have been added in the Western Operating Area as of May 31, 1981. In the Eastern Operating Area, 27 new wells were added as of May 31, 1981.

The total number of oil producing wells connected and producing on May 31, 1981 was 311. Of these, 160 are in the Eastern Operating Area and 151 in the Western Operating Area. In addition, 53 wells have been drilled and completed but are awaiting perforation. The bottomhole locations of the oil producing wells drilled as of May 31, 1981 are shown in Figure 1, together with possible future 160-acre locations.

During the past year, 4 gas injection wells were perforated at the West Gas Injection Pad, bringing the total number of gas injection wells to 18.

Drilling is currently in progress at Drill Sites 12, 14, 16, and 17 in the Eastern Operating Area. In the Western Operating Area drilling is in progress on Drill Pads A, G, H, M, N, and Y.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Continued Development

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMB/D, plus condensate production, in accordance with Conservation Order No. 145. Field facilities will also be available to accommodate gas pipeline deliveries of 2.0 BCF/D when a gas pipeline and plant to condition gas to specification can be completed.

Current plans envision a t .al of 409 wells in the Easte Operating Area and 397 wells in the Western Operating Area by the end of 1984. These well count estimates include current and future 160-acre development wells, water injection wells, and wells proposed for drilling on reduced spacing. Continued development drilling will require the expansion of some Drill Sites/Drill Pads as well as the construction of new ones. Facilities to connect these wells and control their production are either being designed or fabricated and will be installed in conjunction with drilling operations. In regard to reduced spacing an application to change Field Rule 2 (well spacing) of Conservation Order 145, Prudhoe Oil Pool, has been filed with the Alaska Oil and Gas Conservation Commission. Upon approval by the Commission, this will allow wells to be spaced closer than 2000 feet.

Gas injection capacity will be increased with the addition of one low-stage compressor at the Central Gas Injection Plant. Scheduled for delivery on the 1981 barge shipment, this will bring the total number of compressors up to 9 low-stage and 4 high-stage units. The addition of 4 gas injection wells at the West Gas Injection Pad during the past year will provide adequate injection well capacity for the scheduled increase in compression capacity. Sufficient injectivity will be available during normal injection well maintenance or stimulation.

Low pressure systems will be installed in annual increments covering several years. The first increment, to be installed at Flow Station 2, is scheduled to be operational in early 1982. Current plans indicate

that by 1984 all three Flow Stations in the Eastern Operating Area will have low pressure capability. In the Western Operating Area, all Gathering Centers will be fully commissioned for low pressure operation by 1984, with the first increment being installed at Gathering Center 2 in 1983.

It is currently expected that gas lift will commence in 1984 at all Flow Stations in the Eastern Operating Area. Gas lift during 1984 will be accomplished with the installation of one compressor at Flow Station 3 with gas lift transmission lines to the other Flow Stations. Plans for expanding gas lift beyond this initial increment are not yet firm. However, studies are continuing in order to determine the optimum timing and operational aspects of future increments. It is currently expected that by 1986 gas lift gas usage will approach 1.2 BCF/D and will be available at all six Gathering Centers/Flow Stations.

An initial increment of produced water injection facilities was installed at Flow Station 2 during the past year. Flow Station 1 already has produced water injection facilities as a result of the Drill Site 5 water injectivity tests. Current plans indicate that additional increments of produced water injection facilities will be added at each Flow Station/Gathering Center through 1986. By the end of 1986, total installed produced water injection capacity, including spares, is expected to be just under 1.6 MMBWD, with about 900 MBWD capacity in the Western Operating Area and about 700 MBWD capacity in the Eastern Operating Area. Ultimate injection of produced water is currently anticipated to be about 1.0 MMBD. Produced water injection into the Sadlerochit

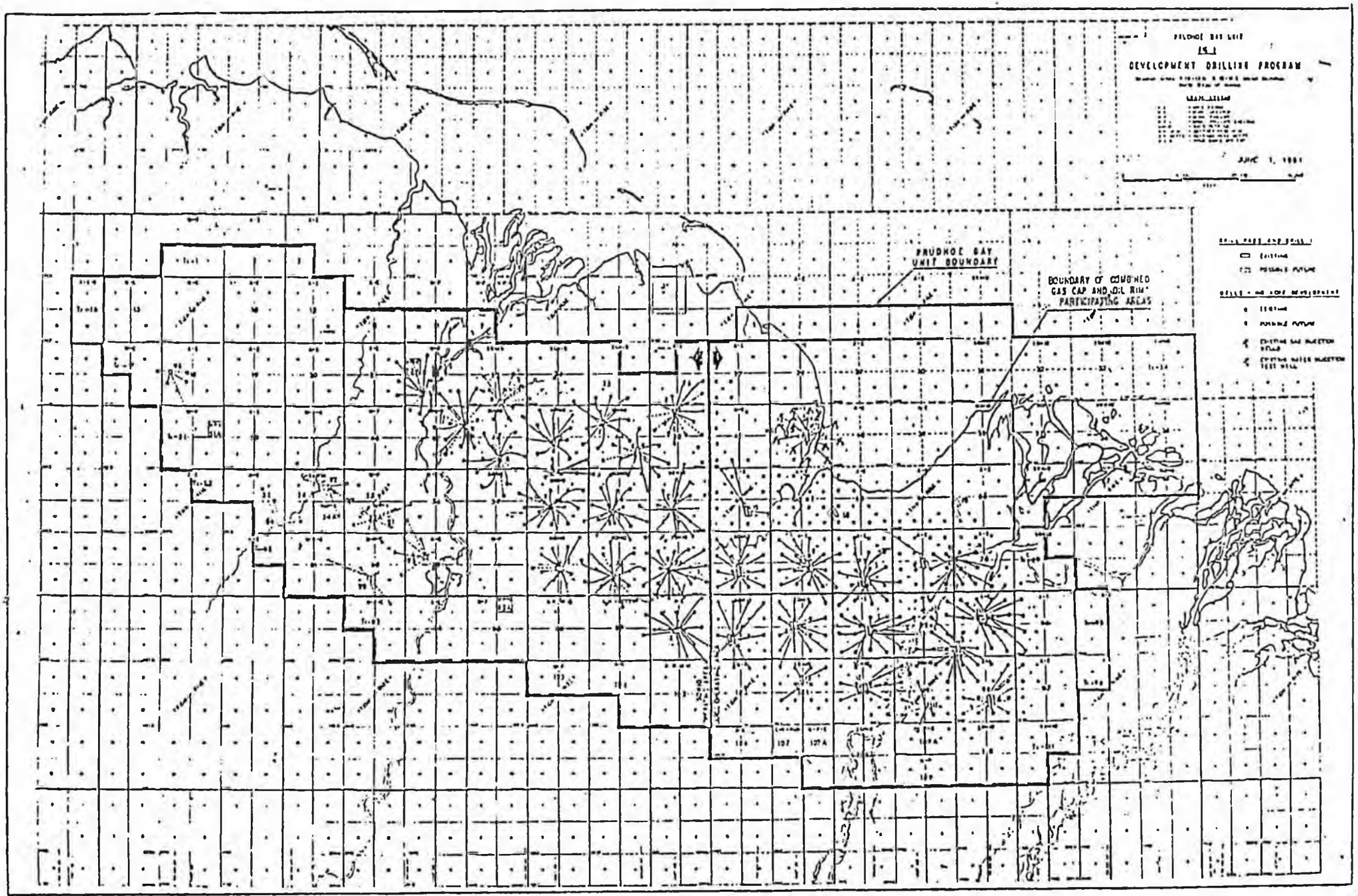
is expected to commence at F / Station 2 when significant ntities of produced water become available. This is currently expected to occur during early 1982.

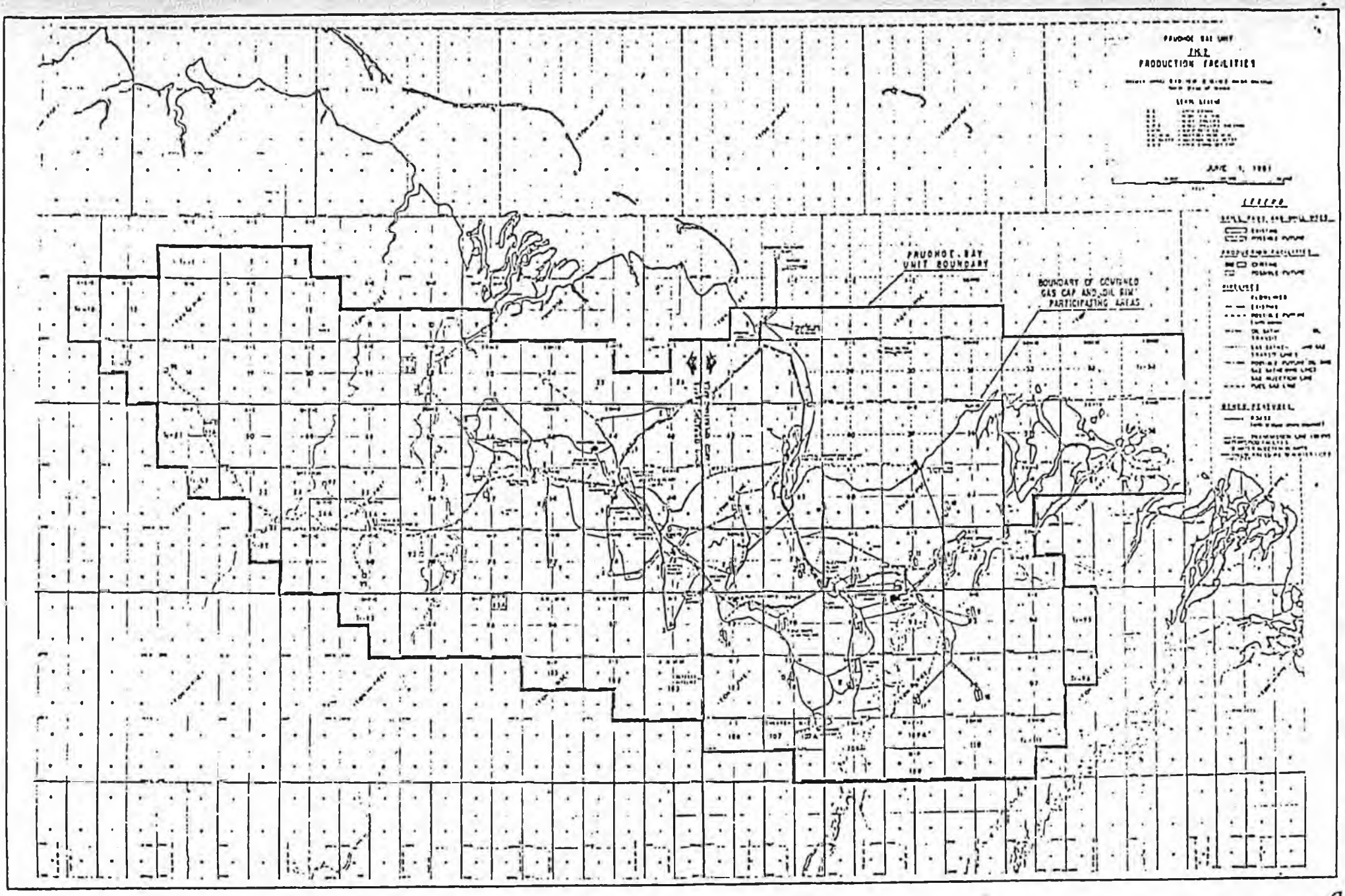
Major milestones toward startup of a sea water source waterflood have been accomplished during the past year. In early May, 1980, a public hearing was held before the Alaska Oil and Gas Conservation Commission (AOGCC) in which the Unit discussed the plans for implementation of a two million barrel per day source water injection program and a produced water injection program. During the last half of 1980, the Environmental Impact Statement process was completed and on January 2, 1981, the U.S. Army Corps of Engineers issued a permit approving the proposed Beaufort Sea water source plant and associated on-shore facilities. As part of the permit, stipulations for a monitoring program were included. This program would allow evaluation of the effects of the dock extension, water intake, and water treatment plant on the local ecosystem. In March, 1981, an Application for Additional Recovery was approved by the AOGCC. All other major permits are now in-hand. These major permits and approvals by the agencies and the AOGCC have allowed the Operators to proceed toward full scale waterflood startup in 1984 with 2 million barrels per day of installed pump capacity. The design and procurement of materials for this major source waterflood is proceeding on schedule. Source water injection is anticipated to commence about mid-1984 at a rate of between 1.5 and 2.0 MMBD.

Reservoir analysis continues with emphasis on waterflood optimization including pattern selection and water volume distribution. Continuing

produced water injection t ing in a five-spot pattern a rill Site 5 will give valuable field information regarding expected waterflood performance in terms of water breakthrough timing, produced water volumes, and injectivity. To date, this pattern has performed as expected. Additional data and understanding has been gained from a Drill Site 5-14 cold water injection test which was run in March and April, 1981. More data will be gathered throughout the field as additional wells are converted to produced water injection.

Reservoir and facilities conceptual design studies are being conducted for development of the Eileen-West End area of the field. During the report period, seven wells were drilled in this area of the field to provide better structural definition of this complex, faulted area. Two existing wells, the Kuparuk well, Sec. 22, T11N, R12E, and the ARCO Highland State #1 well, Sec. 24, T11N, R11E, are scheduled for conversion to pressure observation wells. A Sadlerochit production test is being planned for the Kuparuk well prior to conversion. The geologic, fluid, pressure and production data is being used to improve the reservoir and facilities studies of the area. These studies are addressing well spacing, waterflooding and optimum facilities development.


PRUDHOE BAY UNIT
DEVELOPMENT DRILLING PROGRAM
JUNE 1, 1981
PRUDHOE BAY UNIT BOUNDARY
BOUNDARY OF COMMINGLED GAS CAP AND OIL RIM PARTICIPATING AREAS


PRUDHOE BAY UNIT
PRODUCTION FACILITIES
PRUDHOE BAY UNIT BOUNDARY
BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS

ARCO Alaska, Inc.
P. O. Box 360
Anchorage. AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

July 2, 1981

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
703 W. Northern Lights Boulevard
Anchorage, Alaska 99502

Subject: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Dear Sir:

Sohio Alaska Petroleum Company and ARCO Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1980, as required by the final paragraph of Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,

P. B. Norgaard
Vice President
ARCO Alaska, Inc.

P. J. Martin
Assistant General Mangager
(Operations)
Sohio Alaska Petroleum Company

cr
Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS

OUTSIDE THE INITIAL PARTICIPATING AREAS

PROGRESS REPORT - JULY 1, 1980 TO JUNE 20, 1981

Lisburne Reservoir Area

During the report period, the Lisburne limestone formation was penetrated by one well, Sohio's Sag Delta No. 5 on lease No. ADL 34630. The well was located 727' east of west line and 2322' north of south line, Section 36, T12N, R15E, UPM. The well was spudded February 3, 1981 and drilled to a total depth of 11,063' MD and suspended on April 14, 1981. The results are confidential and are on file with the State Oil and Gas Conservation Commission.

Sohio is presently assessing the geological information obtained from Sag Delta No. 5 before deciding on future drilling activity in the area. A small amount of new seismic data was obtained during the past year and evaluation of the Lisburne Reservoir continued to ascertain its development possibilities.

ARCO is currently in the final design stages of the extended production test planned for the West Bay State No. 1 well. Mechanical problems in the well have delayed startup of the test, which is now expected during the fall of 1981. The extended production test will increase understanding of the productivity of the Lisburne reservoir, and provide information for conceptual development studies. Further delineation drilling may be required to better define Lisburne geology.

PPRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals & Energy Management, Department of Natural Resources. The purpose of this report is to summarize the previous years' activities under the plan of development and operation, which is incorporated in the Unit Agreement as Exhibit 'E'.

Oil Production

Since July 1, 1979 production to the TAPS line has been essentially continuous, with only very brief interruptions. During the period of July 1, 1979 to May 31, 1980, a total of 484 MMB were delivered to the pipeline at an average rate of 1442 MBPD. Total net oil production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) to May 31, 1980 is 1212 MMB, including approximately 2.45 MMB net to the crude oil topping plant.

Gas Production and Injection

Since July 1, 1979 to May 31, 1980 a total of 480 MMMSCF of gas has been produced from the field and 437 MMMSCF was reinjected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 43 MMMSCF has been used as fuel, purge and pilot gas, with only a minor amount flared. Flaring has been reduced to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil & Gas Conservation in Conservation Order No. 145-A, of January 12, 1978.

ARCo Alaska, Inc.
P. O. Box 100360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1984

Director
State of Alaska
Division of Oil & Gas
Department of Natural Resources
Pouch 7-034
Anchorage, AK 99510

RE: PRUDHOE BAY UNIT ANNUAL PROGRESS REPORT

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

L. E. Tate
Vice President
Engineering and Extension Exploration
ARCo Alaska, Inc.

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
0537A
Attachment

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with the provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the prior year's activities under the Plan of Development and Operation which is incorporated in the Unit Operating Agreement as Exhibit "E".

Oil Production

Since June 1, 1983, production to the TAPS line has essentially been continuous at approximately 1.5 MMBOPD, with only a few brief shortfalls occuring during the last year. These shortfalls, which were primarily associated with routine maintenance activities of the Prudhoe Bay Field or TAPS facilities, were made up for the calendar year 1983 as will subsequent shortfalls in 1984. During the period June 1, 1983 through May 31, 1984, a total of 559 MMB of oil and condensate was delivered to the TAPS line at an average rate of 1528 MBPD. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1984 is 3442 MMB, including approximately 7.8 MMB to the Crude Oil Topping Plant.

Gas Production and Injection

From June 1, 1983 through May 31, 1984, a total of 825 BCF of gas was produced from the field and 753 BCF was injected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 72 BCF was used as fuel, purge and pilot gas, or injected in connection with

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

ARCo Alaska, Inc.
P. O. Box 100360
Anchorage, AK 99510

Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1984

Director
State of Alaska
Division of Oil & Gas
Department of Natural Resources
Pouch 7-034
Anchorage, AK 99510

RE: PRUDHOE BAY UNIT ANNUAL PROGRESS REPORT

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

L. E. Tate
Vice President
Engineering and Extension Exploration
ARCo Alaska, Inc.

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
0537A
Attachment

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with the provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the prior year's activities under the Plan of Development and Operation which is incorporated in the Unit Operating Agreement as Exhibit "E".

Oil Production

Since June 1, 1983, production to the TAPS line has essentially been continuous at approximately 1.5 MMBOPD, with only a few brief shortfalls occuring during the last year. These shortfalls, which were primarily associated with routine maintenance activities of the Prudhoe Bay Field or TAPS facilities, were made up for the calendar year 1983 as will subsequent shortfalls in 1984. During the period June 1, 1983 through May 31, 1984, a total of 559 MMB of oil and condensate was delivered to the TAPS line at an average rate of 1528 MBPD. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1984 is 3442 MMB, including approximately 7.8 MMB to the Crude Oil Topping Plant.

Gas Production and Injection

From June 1, 1983 through May 31, 1984, a total of 825 BCF of gas was produced from the field and 753 BCF was injected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 72 BCF was used as fuel, purge and pilot gas, or injected in connection with

the Flow Station 3 Injection Project (FS-3 IP), with only a minor amount flared. Not included in the above is 120 MMCF flared through May 31, 1984, to allow long-term production testing of West End well 21-11-12 in accordance with State of Alaska, Oil and Gas Conservation Commission Order 145 as amended February 14, 1984.

Water Production

Water production between June 1, 1983 and May 31, 1984, was 28.4 MMBW, an average water cut of 4.8%. Of this total, 6.1 MMBW was produced intentionally from four Drill Site 14 wells in the Eastern Operating Area in order to supply sufficient injection water for the FS-3 IP. Excluding water production from the four source wells, total water increased from the 15.2 MMBW the previous report period to 22.4 MMBW during this reporting period. This increased water production is primarily a result of commissioning low pressure production and gas-lift facilities.

In the Eastern Operating Area (EOA), produced water injection into the Sadlerochit is continuing at Drill Sites 12, 13 and 14 in connection with the FS-3 IP and at Drill Site 4. In the Western Operating Area (WOA), produced water injection into the Sadlerochit is continuing at Well Pad R and is planned to be initiated at Well Pads F and X by year-end.

Field Development

As of May 31, 1984, a total of 598 wells were drilled, completed, and connected for production or injection service to their respective separation center, of which 306 and 292 wells were located in the EOA and WOA, respectively. This represents an increase of 94 wells connected for production or injection service over the past year. An additional 56

wells, 23 in the EOA and 33 in the WOA, have been drilled and completed but are awaiting perforation and/or production facilities. The bottom-hole locations of the 654 production and injection wells drilled as of May 31, 1984 are shown on Figure 1. Of the total, 483 wells are 160-acre locations and 171 wells are 80-acre locations. As of May 31, 1984, drilling was in progress at Drill Sites 3 and 12 in the EOA and at Well Pads S and X in the WOA.

Current plans envision an estimated 880 to 950 wells will be drilled in the main area of the field. Of these, 459 to 499 are in the EOA and 421 to 451 are in the WOA. These well count estimates include 160-acre development wells, 80-acre infill wells, water injection wells, and wells associated with the FS-3 IP. Current projections indicate that most of the wells will be drilled by 1988. Continued development drilling will require primarily the expansion of existing drill sites and well pads in addition to the possible construction of one new drill site. Facilities to tie-in these wells are either being designed or fabricated and will be installed coincidental with drilling operations. Following the 1984 Sealift, facilities will be available to accommodate approximately 772 wells.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMBOPD, plus condensate production, in accordance with Conservation Order No. 145. Based on five year planning studies, the Unit expects to maintain this average oil

production rate through 1986. These same studies also indicate that in 1987 the Unit will not be able to maintain this annual average oil rate due primarily to the expanding gas cap combined with finite field gas handling capacity. Field facilities are expected to be available to accommodate gas sales of approximately 2.0 BCFD when gas transportation facilities become available.

All planned low pressure compression facilities for the six separation centers have been sealifted, and by year-end 1984 all will be operational. Gathering Centers 1 and 3 are currently being readied for the start of the low pressure operation while Gathering Center 2 and Flow Stations 1, 2 and 3 systems are operational. Additional gas dehydration capacity is planned for each of the gathering centers in the WOA in the 1987 time frame. Based on current plans, 29 of the 34 producing drill sites and well pads will have low pressure capability by year-end 1984.

The first major increment of the gas-lift system was sealifted in 1983, and is operational at Flow Station 3. Including the smaller gas-lift packages provided in late-1982 for Well Pad X and the FS-3 IP, the nominal compression capacity currently available is 470 MMCFD. The final gas-lift compressor increment, under construction in the Lower 48, is planned to be operational at Gathering Center 1 by mid-1986, and will increase the field-wide capacity to a nominal 1370 MMCFD. The gas-lift transmission line between separation centers is operational and, in effect, provides a header arrangement extending from Gathering Center 2 on the extreme western end of the field to Flow Station 2 on the extreme eastern end. Gas-lift gas discharged from the existing and future compressors can be routed to any of the six separation centers. Ultimate gas-lift usage in the main field currently is projected to be in the 1.3-1.4 BCFD range, but continued studies are

planned based upon system and field performance in the coming years. While recognizing that gas-lift will be provided to wells on a priority and as-needed basis, current plans are that 12 drill sites/well pads in or adjacent to the waterflood areas will have access to gas-lift by year-end 1984. They are Drill Sites 6, 12, 13, 14, 16 and 17 in the EOA, and Well Pads H, M, R, S, X and Y in the WOA. The remaining drill sites/well pads at which gas-lift ultimately is deemed necessary should be tied-in by late 1988.

The Central Compressor Plant (CCP) used to inject produced gas into the gas cap is equipped with nine low-stage and four high-stage turbine-driven compressors. The number of injection wells remains unchanged at 18, with 14 located at the North Injection Pad and four located at the West Injection Pad. Although a miscible gas injection project planned for startup in 1987 (discussed later in the report) will enable increased field gas production rates, additional CCP turbine-driven compressors and injection wells will not be required. However, modifications to the low-stage compressors are planned in order to efficiently handle the lower molecular weight residue gas from the NGL/EOR Plant. Two turbine-driven boost compressors are planned for installation at the inlet of the NGL/EOR Plant.

Produced water injection facilities are in service at five of the six separation centers with only those at Gathering Center 1 remaining to become operational. By year-end 1984, the total available injection capacity will be a nominal 1185 MBWPD with 785 MBWPD being in the WOA and 400 MBWPD being in the EOA. Additional injection capacity under consideration would increase the ultimate to a total of 730 MBWPD in the EOA. While recognizing that the injection capacity available at each of the six separation centers is independent of the others, the total produced water is projected to reach about 1100 MBWPD in the 1988-1989 time frame.

The Prudhoe Bay Unit source waterflood project started up on June 14 with water injection at Drill Site 9, and a step-wise increase in injection rate is underway. Total water injection rates, including produced water, are projected to reach 900-1050 MBWPD by year-end 1984. Combined source and produced water injection rates may reach 2.2 MMBWPD by 1988 based on current predictions. A reservoir surveillance program was submitted to the Alaska Oil and Gas Conservation Commission in accordance with the Unit's application for additional recovery by waterflood in December, 1980.

During the past year, the injection pattern has been selected for the western Peripheral Wedge Zone (PWZ) and the previously selected Northwest Fault Block (NWFB) pattern has been modified. The Flow Station 2 and eastern PWZ long-term injection patterns remain unchanged. In the NWFB, an 80-acre per well inverted nine-spot waterflood pattern will be utilized to better accommodate future miscible gas injection. Waterflooding in the Peripheral Wedge Zone will be based on a similar development, with the exception of the H and U-Pad area where the narrow target favors a line-drive approach.

Reservoir and facilities conceptual design studies for development of the Eileen-West End area of the field have continued during the past year. Information being obtained from evaluation of the long-term test of well 21-11-12 will be key to defining the ultimate development of the West End area. An interpretation of 650 miles of 3-D seismic surveys taken early this year will provide further definition of the structural configuration and ultimate potential in the coming year. Continuing reservoir studies, now incorporating the above information, will be used to determine an optimum depletion strategy. Likewise, continuing facility studies will define development options.

Design engineering is underway toward the implementation of a large scale enhanced oil recovery project, the Prudhoe Bay Miscible Gas Project (PBMGP), to start up as early as 1987. PBMGP facilities will consist of an NGL/EOR Plant providing TAPS transportable NGLs and miscible injectant, as well as injectant compression, distribution, and well site injection facilities. Engineering design studies are currently underway, and are aimed toward a 1986 Sealift. The Project is expected to affect about 10% of the Sadlerochit reservoir and will be applied in areas already under waterflood at that time. At startup, water alternating miscible gas (WAG) injection is planned to begin in 42 patterns utilizing then existing water injectors. Activities aimed at optimizing EOR performance will continue through analysis of FS-3 IP and waterflood response and additional studies. The PBMGP was certified by the Alaska Oil and Gas Conservation Commission as a qualified tertiary recovery project on March 5, 1984.

Miscible gas injection in the FS-3 IP resumed on April 22, 1984, after interruption by an explosion and fire on May 26, 1983. While the rebuild effort resulted in minor system changes, facility capacity remains essentially unchanged at approximately 49 MMCFD of miscible injection. During the interruption of miscible gas injection, water injection and production activities were managed to maintain a proper reservoir pressure level. All 60 wells related to the Project have been drilled and perforated. Miscible gas injection currently averages about 43 MMCFD with water injection averaging about 74 MBWPD. Repeat logging of observation well 13-98 continues to provide valuable insight regarding water movement in the Sadlerochit. Current plans are to continue operating the FS-3 IP independently of the Prudhoe Bay Miscible Gas Project scheduled for startup in 1987 although facilities to link the two projects are planned.

ARCo Alaska, Inc.
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Sohio Alaska Petroleum Company
Pouch 6-612
Anchorage, AK 99502

June 29, 1984

Director
State of Alaska
Division of Oil & Gas
Department of Natural Resources
Pouch 7-034
Anchorage, AK 99510

Rec. 3 pm

RE: EXHIBIT E-1
PLAN OF DEVELOPMENT AND OPERATION FOR
LANDS OUTSIDE THE INITIAL PARTICIPATING
AREAS - PRUDHOE BAY UNIT AGREEMENT
STATE OF ALASKA

Sohio Alaska Petroleum Company and ARCo Alaska, Inc., as Operators of the Prudhoe Bay Unit, respectfully submit herewith a progress report for the twelve (12) months ending June 1984, as required by the final paragraph of the Exhibit E-1 to the Prudhoe Bay Unit Agreement.

Sincerely,

L. E. Tate
Vice President
Engineering and Extension Exploration
ARCo Alaska, Inc.

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
0531A
Attachment

PLAN OF DEVELOPMENT AND OPERATION FOR LANDS
OUTSIDE THE INITIAL PARTICIPATING AREAS
PROGRESS REPORT: JULY 1, 1983 TO JULY 1, 1984

LISBURNE RESERVOIR

Considerable progress was made in the past year in further delineating the Lisburne Reservoir. It is anticipated that a Participating Area for the Lisburne will be established sometime from mid-1985 to late 1986 in accordance with Article 5.3 of the Prudhoe Bay Unit Agreement.

During the report period, four delineation wells have been completed by the Owners in the Lisburne Development.

Owner	Well Name	Bottom Hole Location
ARCo/Exxon	South Point State #1	18-11-15
ARCo/Exxon	Pingut State #1	24-11-15
ARCo/Exxon	South Bay State #1	22-11-15
Sohio	Sag Delta #6	2-11-15

These wells were extensively cored, logged and drill stem tested in order to evaluate the Lisburne continuity, reserves, and productivity. A two-month production test has been completed on each of the three ARCo/Exxon wells, and a similar test is underway on the Sohio well. Extensive geological, geophysical and reservoir engineering studies are ongoing in order to evaluate and optimize reservoir development of the Lisburne. The data obtained from the above four delineation wells plus previous drilling provides the basis for these studies. It currently appears that the Lisburne Development is contained entirely within the Prudhoe Bay Unit. A development decision is expected during the third quarter 1984.

Conceptual and preliminary facility designs have been completed and final engineering was initiated in January, 1984. Drill site modules are planned to be fabricated and sealifted in 1985 with sealift of production center facility modules planned for 1986. The Lisburne Production Center (LPC), to be commissioned by early 1987, will be located south of Drill Site 18 and will be designed to process a nominal 100 MBOPD and 400 MMCFD of gas with later expansion to 600 MMCFD, if necessary.

The crude oil stream from the drill sites will be routed through a trunk and lateral gathering system to the LPC. The produced gas will be stripped of NGLs prior to injection into the Lisburne reservoir. The NGLs will be blended with the processed crude oil up to allowable TAPS vapor pressure specifications. The commingled stream will than be transported from the LPC, by a separate pipeline, directly to Pump Station 1. The LPC, which is designed to be self-sufficient, will include separation trains, NGL recovery trains, power generation facilities, and compressors for gas injection.

The Lisburne wells will be directionally drilled from centralized gravel pads. Development plans call for seven drill sites, one of which will be an island in Prudhoe Bay that will be accessible by a causeway. It is anticipated that up to 200 producing wells will be drilled on 160-acre spacing with eight to twelve gas injection wells, and one water disposal well. Drilling is expected to begin in the second half of 1984 and the program may include up to four rigs by 1986.

Major permit applications including gravel, NPDES, and PSD permits have been submitted. Several agencies have indicated concern over a gravel causeway and discussions are underway to resolve this issue. The Lisburne Owners also plan to seek field rules approval from the AOGCC during 1984.

KUPARUK RESERVOIR

During the report period, the Kuparuk interval was penetrated by two Prudhoe Bay Unit Sadlerochit development wells drilled from the S-Pad located in Sec. 35, T12N, R12E. The results of these wells are on file with the State.

Well	BHL	Spud Date	Completion Date	Total Depth (MD)	Lease ADL #
S-4	34-12-12	7-19-83	8-9-83	9575'	28258
S-5	35-12-12	6-28-83	7-19-83	10810'	28257

The S-4 well was logged through the Kuparuk interval and 116 feet of core was acquired in the Kuparuk. Another S-Pad well is to be logged, conventionally cored, and extensively side-wall sampled later this year. These data together with additional seismic data and potential further delineation drilling information will be incorporated into an ongoing study to determine the development potential of the Kuparuk reservoir within the Unit area.

ENDICOTT

As noted in last year's report, it appears that the Endicott Reservoir underlies leases in the northeast corner of the Prudhoe Bay Unit, the adjacent Duck Island Unit, as well as State leases that are not currently included in any Unit. As a consequence, many Endicott activities are being undertaken cooperatively by the Endicott group of leaseholders (Sohio Alaska Petroleum Company, ARCo Alaska, Inc., Exxon Corporation, Union Oil Company of California, Amoco Production Company, Cook Inlet Region, Inc., NANA Regional Corporation Inc., and Doyon Ltd.). The Director has been kept advised of Endicott activities in various contacts with the Endicott leaseholders.

The Endicott Project progressed from the conceptual engineering phase to the preliminary engineering phase in mid-1983. The reservoir description of the field was updated and reservoir models to simulate various reservoir management strategies were developed. Unitization efforts are ongoing.

Summary of Work Progress

Work planned for the 1983-1984 period was essentially completed and goals were met. Details of the work performed in 1983-1984 are summarized below.

Work Conducted Since Previous Report

(i) Geophysical

The 3-D seismic data obtained in early 1983 has been processed.

(ii) Engineering Studies

The Endicott leaseholders contracted Ralph M. Parsons to perform preliminary engineering studies of such items as the islands, causeway, access road, and facilities. Santa Fe Braun was contracted to perform preliminary engineering studies for the drilling facilities and all the pipeline related work. All of the preliminary engineering studies have been completed, and a definitive cost estimate for the project is being prepared at this time. Additional work and studies performed include:

- Hydrology Study
- Ice Force Study
- Gravel Source Study
- Water Compatibility Tests
- Crude Gel Tests
- Crude Dehydration Tests
- Coastal Engineering Study
- Pipeline Thermal Modeling
- Winter Geotechnical Study
- 3-D Hydraulic Model Study
- Wellbore Thermal Modeling

At this time, the project design includes:

- One Main Production Island with drilling, well testing, and processing facilities for a nominal 100 MBOPD and 200 MMCFD of produced gas, and an NGL extraction plant.

- One Satellite Drilling Island with drilling and well testing facilities.
- A gravel causeway connecting the islands and the islands to the shore.
- A Waterflood Intake Structure located on the north side of the Main Production Island.
- Main Construction Camp and Base Operations Camp located on the Main Production Island.
- Tie-in capability for a maximum of 120 wells.

(iii) Environmental/Permits

Environmental Research Technology (ERT) was contracted to prepare the Environmental Impact Statement (EIS) for the Endicott Project. A Draft EIS was issued in January 1984. Public hearings were held on March 1st and March 5th in Barrow and Anchorage, respectively. Public and Agency comments were handled by the Corps of Engineers and ERT with Endicott leaseholder assistance. A Preliminary Final EIS was then issued in the second quarter of 1984 for comment. The basic concern of the Agencies was the use of a solid fill causeway. The Endicott leaseholders are prepared to construct a breach in the causeway and are discussing the size, location and design of the breach with State, Federal and Borough Agencies. Numerous permit filings including NPDES and PSD permits have been made in support of the project. The Endicott leaseholders have also conducted discussions with the AOGCC directed towards a public field rules hearing.

(iv) Unitization

The Endicott leaseholders continue working to finalize unitization. The expected plan of unitization will be to delete leases ADL 34633, 34634 and 34636 from the Prudhoe Bay Unit, and at the same time expand the Duck Island Unit to

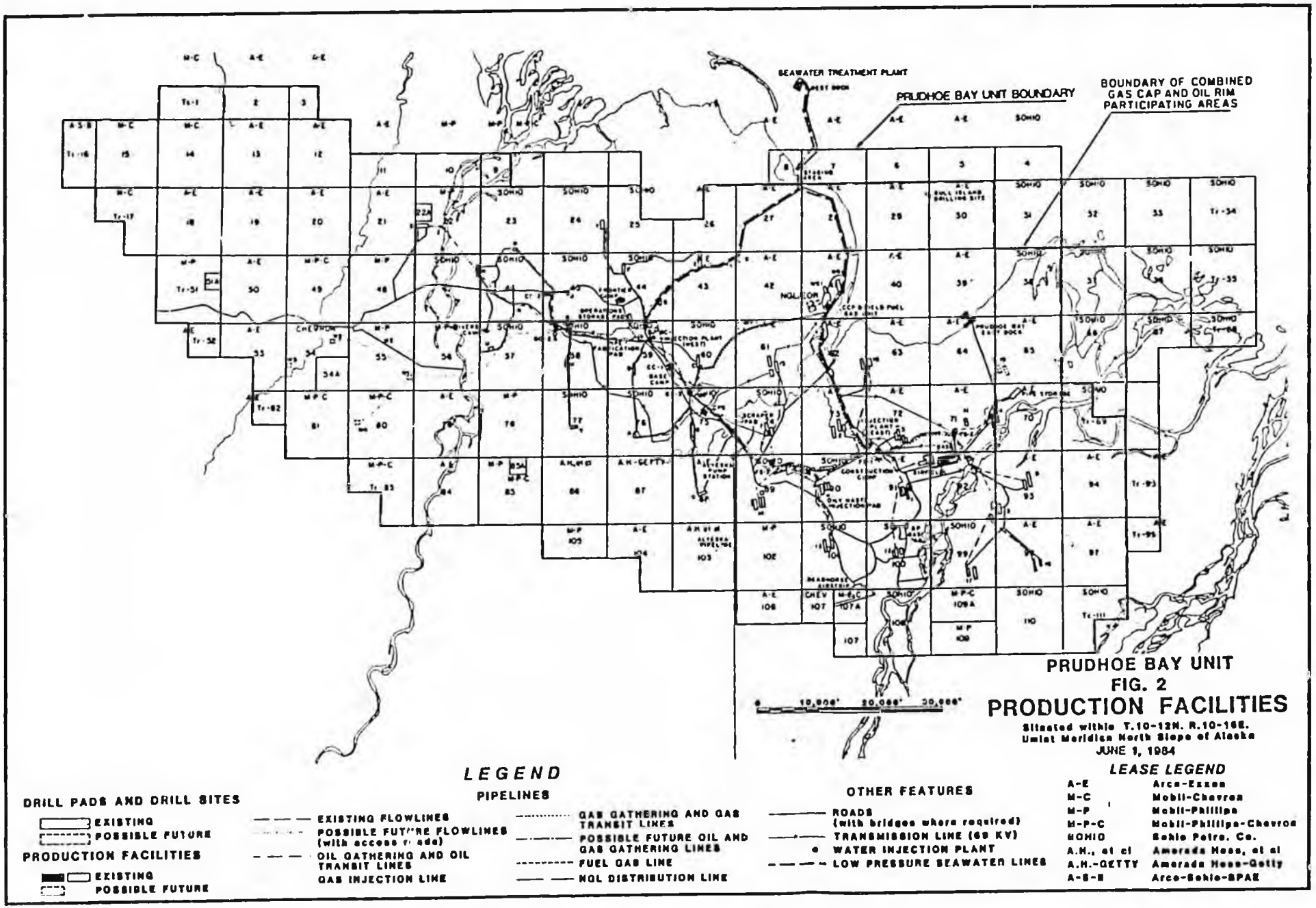
include those leases listed above as well as adding leases ADL 312828 and 312834. The Endicott leaseholders are working with the Division of Oil and Gas, Department of Natural Resources, to secure necessary State approvals.

Work in Progress

The major objective continues to be to work towards a development decision by year-end 1984 to preserve an option for a 1988 field startup. A detailed cost estimate has been issued and engineering studies to assist in optimization of the project will continue. Detailed engineering will commence in the third quarter of 1984 and continue through 1985. If the project goes forward, gravel placement for the haul road and causeway will begin in late 1984 or early 1985. The Final Environmental Impact Statement (FEIS) should be issued in mid-1984. Permit applications will be pursued.

NORTH PRUDHOE BAY (PERMO-TRIASSIC)

During the report period there were no wells drilled nor was there any seismic data acquired in the North Prudhoe Bay area.

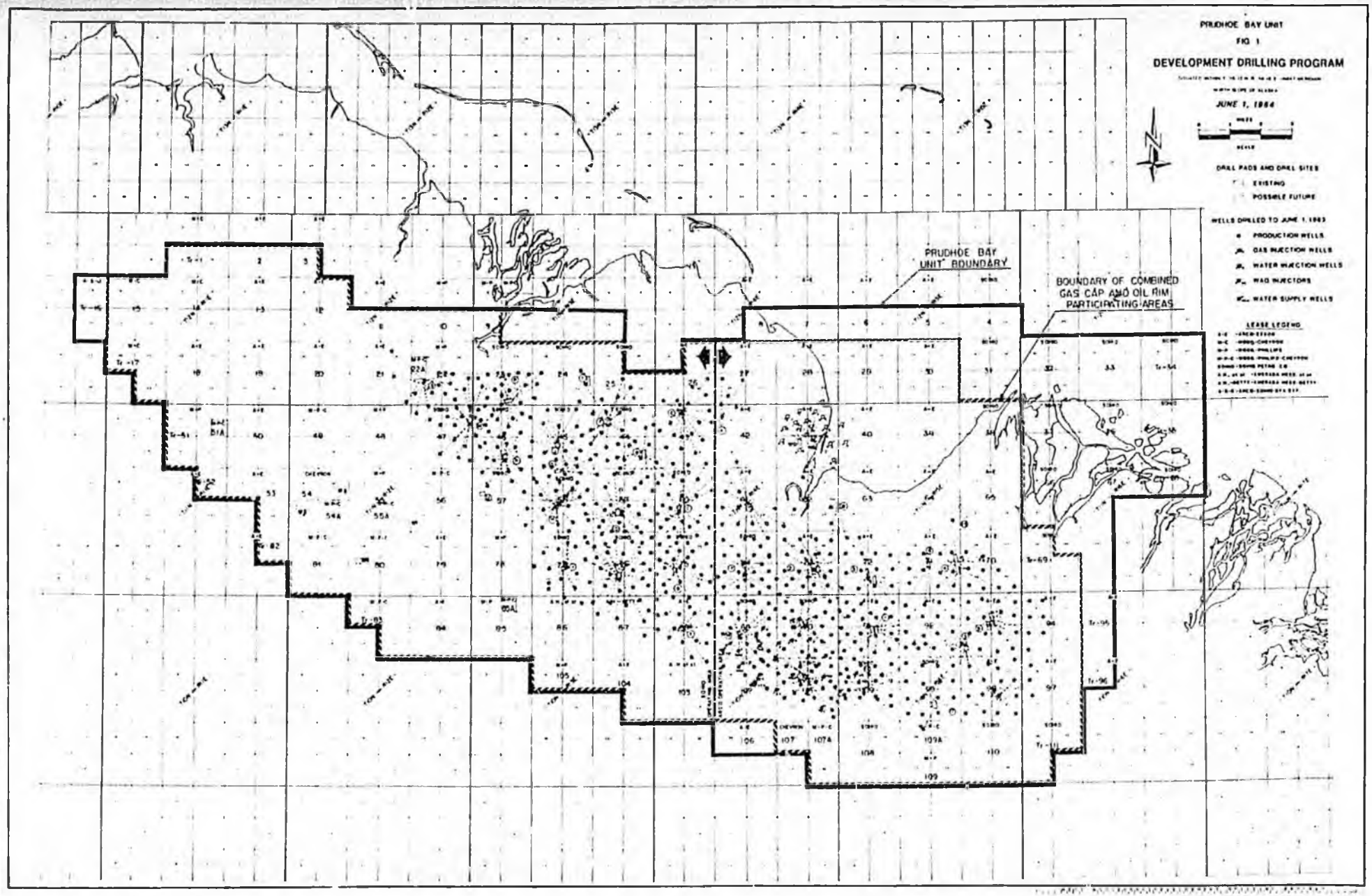


PRUDHOE BAY UNIT

FIG. 2

PRODUCTION FACILITIES

Situated within T.10-12N. R.10-16E.
Umiat Meridian North Slope of Alaska
JUNE 1, 1984


PRUDHOE BAY Unit
FIG. 1
DEVELOPMENT DRILLING PROGRAM
JUNE 1, 1984
DRILL PADS AND DRILL SITES
EXISTING
POSSIBLE FUTURE
WELLS DRILLED TO JUNE 1, 1984
PRODUCTION WELLS
GAS INJECTION WELLS
WATER INJECTION WELLS
WAG INJECTORS
WATER SUPPLY WELLS
LEASE LEGEND
PRUDHOE BAY UNIT BOUNDARY
BOUNDARY OF COMBINED GAS CAP AND OIL RIM PARTICIPATING AREAS

File PBU
RECEIVED PODS.

PRUDHOE BAY UNIT - LISBURNE DEVELOPMENT

Project Description. Consistent with the Prudhoe Bay Unit Operating Agreement, ARCO Alaska, Inc., as Operator, has completed a delineation tract well and production testing program that has proven the commerciality of the Lisburne Reservoir. Pursuant to the Unit Agreement, a separate Participating Area will be created within the Prudhoe Bay Unit for the Lisburne horizon. The oil from the estimated 3 billion barrel reservoir will be initially processed at a nominal rate of 100,000 barrels of oil per day and 400 million cubic feet of gas per day. Optimum production startup is targeted for late 1986/early 1987 (prior to anticipated Prudhoe Bay Unit Permo-Triassic production decline). The areal extent of the identified Lisburne Reservoir encompasses onshore and offshore State 1/8 royalty leases. Approximately 25-30% of the Lisburne production will be recovered from the proposed offshore facility. The offshore drill site/injection site is located above the largest known gas cap in North America. Onshore facilities include 5 new drill sites (all partially built), connecting pipeline corridors, and a Lisburne Production Center. The locations of the project and facilities are integrated into and share as much existing Prudhoe Bay Unit facilities as possible.

Permit Status. State, Federal and local government permit applications were filed May 4, 1984. The filings culminate one year plus of ARCO/Agency coordination which has produced several documents detailed below. Studies to date identify Prudhoe Bay as an open water shoal protected (2' water depth at shoal) coastal area which, for the most part, freezes to the bottom in winter. Oceanographic impacts appear limited to the Bay, since the proposed causeway aligns with predominant winds and currents. Nevertheless, common concerns for Beaufort Sea causeways continue to be voiced. Subsea pipeline ($30-50 million incremental) and elevated pile support ($250 million incremental) designs have been discussed. Breaches 100' to 1300' in width ($20-40 million incremental) have also been addressed, even though the studies do not justify a breach. Unnecessary and unjustified offshore mitigative burdens will push the offshore project costs past the feasible and prudent pivot point, thereby, favoring an onshore contingency development plan resulting in lost offshore recoverable reserves. As always, ARCO has mitigated many of the onshore concerns over the past year through State, Federal and local government coordination meetings and through use of the Lisburne study documents. Additional onshore mitigation representing $30 million worth of incremental costs has been formally requested by one commenting agency. Further onshore mitigation will be considered as it conforms to current Prudhoe Bay Unit operating practices and sound field development principles.

Project Documents.

1. Lisburne Development Area 1983 Environmental Studies, 12/15/83 (Agency designed).

2. Lisburne Project Environmental Impact Assessment, 2/6/84.

3. PBU Lisburne Development Facilities Justification and Alternatives Paper, 4/10/84.

4. Lisburne Development Drainage and Erosion Control Design and Criteria Manual, May 1984.

5. U. S. Army Corps of Engineers, Lisburne Project Environmental Assessment, May, 1984.

PRUDHOE BAY UNIT - LISBURNE
DEVELOPMENT

Executive Summary

Project Components: Six drill sites [one offshore drill site/injection site, five onshore drill sites (all partially built)], connecting pipelines, gravel causeway (possible breach), one onshore gas injection site, Lisburne Production Center, Put River pipeline crossing.

Construction Schedule:

1984 Onshore-drill site expansions, pipeline/construction pads, Lisburne Production Center, onshore gas injection pad.

1985 Put River Crossing, offshore drill site/injection site and causeway to +4' above water elevation, Sealift (drill site buildings and heaters).

1986 Offshore drill site/injection site and causeway to +15' above water elevation, Sealift (Lisburne Production Center Modules)

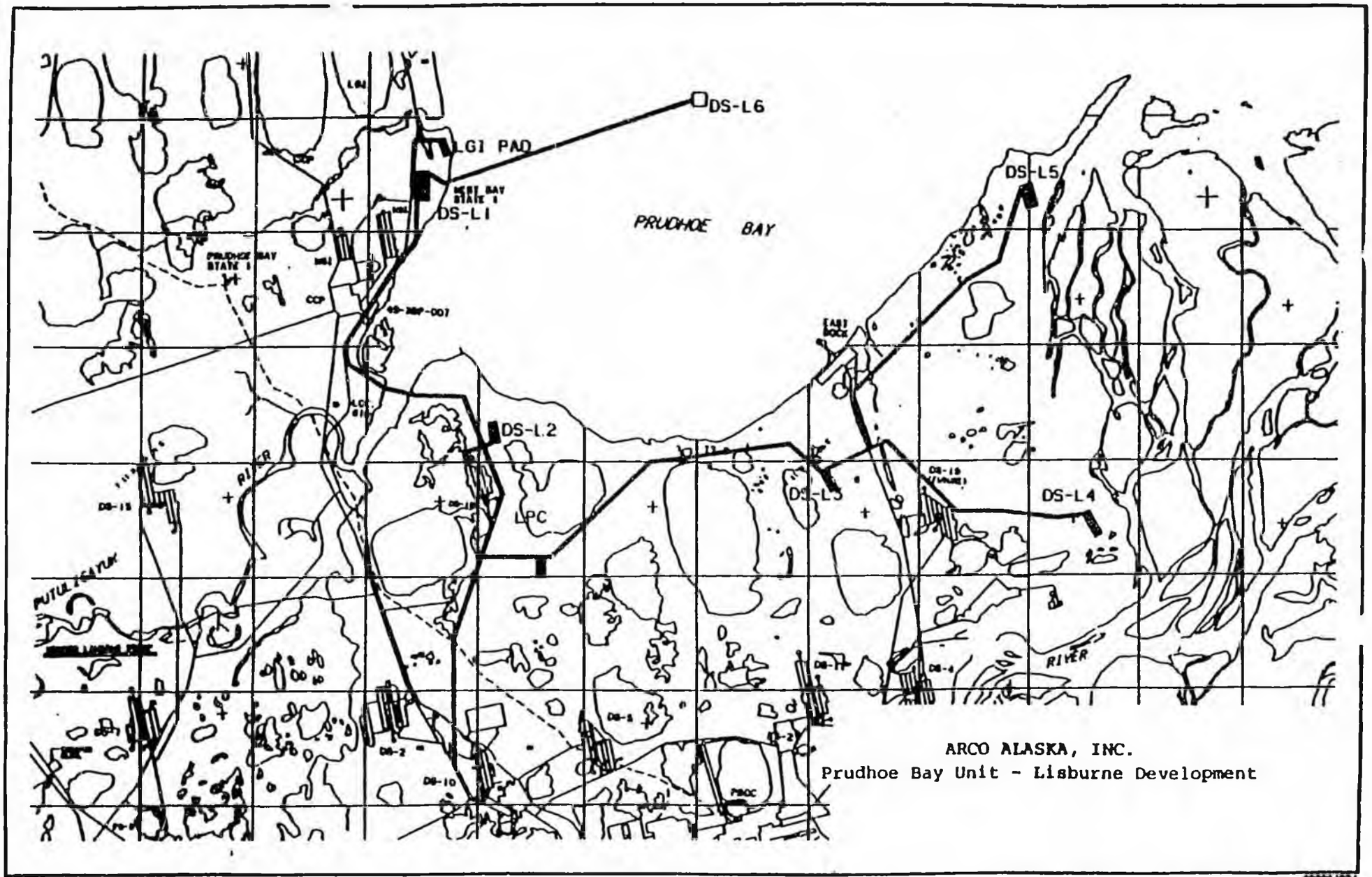
1986-87 Lisburne Startup

Controversial Aspects:

1. Gravel causeway (breach or no breach, if breach, what size?)
2. Pipeline construction pads
3. Pipeline corridor and crossing over Put River

Project Alternatives:

	Alternatives	Incremental Costs
1.	Subsea Buried Pipeline	$30-50 million
2.	Elevated Pile Supported Causeway/Pipeline	$250 million
3.	Breached Causeway	
	a. 100'	$20 million
	b. 600'	$30 million
	c. 1300'	$40 million
4.	Follow Existing Pipeline Corridors (Along East Dock Road to PBOC to West Dock Road to Drill Site 18)	$20 million
5.	Follow Existing Put River Crossing	$8-10 million



ARCO ALASKA, INC.
Prudhoe Bay Unit - Lisburne Development

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Sohio Alaska Petroleum Company
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June 29, 1983

Director
State of Alaska
Division of Minerals & Energy Management
Department of Natural Resources
555 Cordova
Anchorage, AK 99501

EXH E

1st update to 5 year POD

RE: PRUDHOE BAY UNIT ANNUAL PROGRESS REPORT

In accordance with the requirements of the Prudhoe Bay Unit Agreement, we are submitting an annual progress report of the activities performed under the Plan of Development included as Exhibit 'E'.

If you should have questions regarding this report, please do not hesitate to contact the undersigned.

Sincerely,

Leland E Tate

L. E. Tate
Vice President
Engineering and Extension
Exploration
ARCO Alaska, Inc.

Paul J. Martin

P. J. Martin
Vice President
Operations and Engineering
Sohio Alaska Petroleum Company

csr
Attachments

PRUDHOE BAY UNIT

ANNUAL PROGRESS REPORT

In accordance with the provisions of the Prudhoe Bay Unit Agreement, this Annual Progress Report has been prepared for submission to the Director, Division of Minerals and Energy Management, Department of Natural Resources. The purpose of this report is to summarize the prior year's activities under the Plan of Development and Operation which is incorporated in the Unit Agreement as Exhibit "E".

Oil Production

Since June 1, 1982, production to the TAPS line has been essentially continuous at approximately 1.5 MMSTB/D, with only a few brief shortfalls occurring during the last year. These shortfalls were primarily associated with normally planned maintenance activities of the Prudhoe Bay Field or TAPS facilities. During the period June 1, 1982 through May 31, 1983, a total of 558 MMB of oil and condensate was delivered to the TAPS line at an average rate of 1528 MSTB/D. Total net oil and condensate production from the field from April 1, 1977 (the effective date of the Prudhoe Bay Unit) through May 31, 1983 is 2883 MMB, including approximately 6.53 MMB to the crude oil topping plant.

Gas Production and Injection

From June 1, 1982 through May 31, 1983, a total of 797 BSCF of gas was produced from the field and 732 BSCF was reinjected into the gas cap of the Prudhoe Oil Pool. The majority of the remaining 65 BSCF was injected in the Flow Station 3 Injection Project or used as fuel, purge and pilot gas, with only a minor amount flared. All flaring is being held to practical minimums and has been in accordance with the rules established by the State of Alaska, Division of Oil and Gas Conservation in Conservation Order No. 145-A of January 12, 1978.

Water Production

Water production between June 1, 1982 and May 31, 1983, totalled 20.3 MMB. Of this total, 5.1 MMB was produced intentionally from four Drill Site 14 wells in the Eastern Operating Area in order to supply sufficient water for the Flow Station 3 Injection Project (enhanced oil recovery project utilizing miscible gas displacement). Excluding water production from the four source water wells, total water increased slightly from 12.6 MMB the previous year to 15.2 MMB the past year. In the Eastern Operating Area, produced water injection into the Sadlerochit has been initiated at Drill Sites 13 and 14 in connection with the Flow Station 3 Injection Project and at Drill Site 4 at Flow Station 2. Routine injection into the Sadlerochit in the DS 5-17 well is continuing but will be replaced as injection is initiated in the Drill Site 12 area later this year. In the Western Operating Area, produced water injection into the Sadlerochit has been recently initiated at Well Pad R at Gathering Center 2. Produced water injection into the Sadlerochit will occur in late 1983 at X-Pad at GC-3. GC-1 will continue injection into the Cretaceous/Tertiary sands until mid-1984, at which time Sadlerochit injection facilities will become available.

Additional Wells and Facilities

As of May 31, 1983, a total of 504 wells were drilled, completed, and connected for production or injection service to their respective Flow Stations/Gathering Centers, of which 265 and 239 wells were located in the Eastern and Western Operating Areas, respectively. An additional 105 wells, 31 in the East and 74 in the West, have been drilled and completed but are awaiting perforation and/or production facilities. The bottom-hole locations of the oil producing wells drilled as of May 31, 1983 are shown in Figure 1. Of the total 609 wells drilled as of May 31, 1983, 468 are 160-acre locations and 141 are 80-acre locations.

As of May 31, 1983 drilling was in progress at Drill Sites 13 and 14 in the Eastern Operating Area. In the Western Operating Area, drilling was in progress at Well Pads J and M.

Current plans envision an estimated 915 to 984 development wells for the main area of the field, or 478 to 516 wells in the Eastern Operating Area and 437 to 468 wells in the Western Operating Area. These well count estimates include current and future 160-acre development wells, 80-acre infill wells, and water injection wells. Current projections of drilling activity levels indicate that most of the wells will be drilled by 1987. Continued development drilling will require the expansion of some drill sites/well pads as well as the construction of new ones. Facilities to tie-in these wells are either being designed or fabricated and will be installed coincidental with drilling operations. For example, following the 1983 sealift, facilities will exist to accommodate approximately 710 wells; following the 1985 sealift, current planning envisions up to approximately 845 wells can be accommodated.

Figure 2 shows the location of existing production facilities, pipelines, roads, bridges, airstrips and base camps, together with facilities under construction and possible future facilities.

Well and facility additions are continuing in order to ensure that adequate field capacity is available to meet oil pipeline demand up to a maximum annual average oil rate of 1.5 MMSTB/D, plus condensate production, in accordance with Conservation Order No. 145. Field facilities are also expected to be available to accommodate gas pipeline deliveries of approximately 2.0 BSCF when a gas conditioning plant and pipeline are completed.

Low pressure systems will be installed at each of the Flow Stations/Gathering Centers in annual increments over several years. In the Eastern Operating Area, low pressure systems at Flow Stations 2 and 3 were commissioned in the last half of 1982, and current plans indicate that Flow Station 1 will have low pressure capability by early 1984. In the Western Operating Area, all Gathering Centers will have low pressure capability by mid-1984 with the first increment planned for startup at Gathering Center 2 later this year. Based on current plans, approximately 27 producing drill sites/well pads will have low pressure capability by late-1984 with the remainder by late 1987.

Gas lift was initiated in late-1982 with the commissioning of a nominal 30 MMSCFD capacity compressor at Gathering Center 3 for X-Pad usage in the Western Operating Area. An additional 45 MMSCFD of gas-lift capability was also commissioned in late 1982 at Flow Station 3 in the Eastern Operating Area in connection with the Flow Station 3 Injection Project. Approximately two-thirds of the Flow Station 3 gas-lift capacity is currently being utilized to produce source water wells for the Injection Project with the remaining capacity available for oil production at Drill sites 13 and 14. In early 1984, the gas-lift system will be expanded to other areas with the installation of a nominal 375 MMSCFD capacity compressor at Flow Station 3, gas-lift transmission lines between Gathering Centers and Flow Stations, and a tie line connecting the two sides of the field. Currently, it is anticipated that other large gas-lift increments will be commissioned in 1986 and 1987. Current predictions envision gas-lift usage in the main field area to be 1.3 to 1.4 BSCFD by 1987; however, further study and field performance is required to better define the timing of future increments and the ultimate gas-lift system requirements. Gas lift will be provided to drill sites/well pads on a priority basis. Based on the current plan, approximately 13 producing drill sites/well pads will have gas-lift capability by late 1984, with the remaining equipped by late 1988.

The Central Gas Injection Plant is currently equipped with nine low-stage and four high-stage compressor units. Eighteen gas injection wells are currently available, including fourteen at the North Injection Pad and four at the West Injection Pad. Adequate gas injection well capacity is available to accommodate the capacity of the Injection Plant during normal well maintenance and/or stimulation downtime.

Produced water injection facilities have been installed at the three Flow Stations in the Eastern Operating Area, and at Gathering Centers 2 and 3 in the Western Operating Area. Facilities for Gathering Center 1 will be sealifted this year and are expected to be operational by mid-1984. By the end of 1987, total installed injection capacity is expected to be approximately 1.7 MMBWPD, with about 900 MBWPD capacity in the Western Operating Area and 800 MBWPD capacity in the Eastern Operating Area. Ultimate injection of produced water is currently projected to be about 1.3 MMBWPD.

The Prudhoe Bay Unit source waterflood project remains on schedule for the planned mid-1984 startup of source water injection. Initial rates including produced water are projected to be in the range of 1.4-1.5 MMBWPD in 1984. The basic waterflood plans and implementation schedule presented in the May 1980 Prudhoe Oil Pool Rules Hearing and the December 1980 Secondary Recovery Permit Application are unchanged at this time. Fabrication of the Seawater Treating Plant and East and West side injection facilities are on schedule and will arrive on the North Slope in the 1983 Sealift. The 1982 environmental monitoring program results have been provided to the Corps of Engineers, and planning for the 1983 program is nearing completion. Additionally, development of a comprehensive reservoir surveillance program is underway in conjunction with detailed waterflood implementation planning.

Injection patterns have been selected for the major waterflood areas which are scheduled for startup in mid-1984. These areas are the Northwest Fault Block, Flow Station 2 and the eastern Peripheral Wedge Zone. An injection pattern for the western portion of the Peripheral Wedge Zone will be selected by year-end 1983 with waterflood startup planned for 1985. An 80-acre peripheral waterflood pattern is currently planned for the Northwest Fault Block. Based on waterflood performance, a row of centerline injectors along the central fault block may be added at a later date to enhance recovery. In the Flow Station 2 area, combination 320-acre inverted nine-spot/five-spot patterns will be implemented with the five-spot patterns used primarily in the updip and downdip areas. As infill development drilling proceeds, the five-spot patterns may evolve into inverted nine-spot patterns. A 320-acre inverted nine-spot pattern is also planned for the eastern Peripheral Wedge Zone with portions of the area initially developed on an inverted five-spot pattern. As in the case of the Flow Station 2 waterflood, the five-spot patterns may evolve into nine-spot patterns as infill drilling proceeds.

Reservoir and facilities conceptual design studies for development of the Eileen - West End area of the field have continued during the past year. Preliminary facility study results indicate that the preferred method of processing West End production would be to utilize Gathering Center 2, rather than a separate production facility. Reservoir and geologic studies have continued to address such questions as well spacing, waterflooding, and production performance estimates. Pressure measurements being obtained from the observation well Kuparuk 22-11-12 are being incorporated into the reservoir simulation work.

The Flow Station 3 Injection Project, an enhanced oil recovery project employing miscible gas displacement, commenced operation in December 1982. Injection of miscible fluids was initiated in well 13-19 on December 30, 1982.

The project area encompasses some 3650 acres in the downdip area of Flow Station 3 and consists of eleven inverted nine-spot injection patterns. A total of 60 wells are included in the Project, of which 42 are producers, 7 are water injectors and 11 are water/miscible gas (WAG) injectors. As of May 31, 1983, all Project wells with the exception of 1 producer had been drilled. In addition, an observation well has been drilled in the Project area for surveillance purposes. The remaining producer is currently being drilled. Facilities associated with the project include two 15 MMSCFD compressors and one 14 MBD liquid pump which can provide up to 49 MMSCFD of miscible injectant for injection into eleven WAG wells at Drill Site 13. The water for the WAG wells and initial water injection into the seven upstructure water injectors is being provided by existing produced water facilities at Flow Station 3 supplemented with approximately 50 MBWPD of gas-lifted Sadlerochit aquifer water from four Drill Site 14 source water wells. Gas-lift gas to produce the source water wells is provided by three Solar compressors located at Flow Station 3 which have a nominal capacity of approximately 45 MMSCFD. During the month of May 1983, injection rates in the Project averaged approximately 42 MMSCFD of miscible injectant and 62 MBWPD in the water injectors.

On May 26, 1983 an explosion and fire occurred in the Injection Module, thereby halting injection into the Project area. Damages are currently being assessed and future courses of action are being evaluated.