

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILE 8672
2118 SCOMM 79: HOUSE SPEC. COMM. ON OIL & GAS, 1991-1992

136

tissues contaminated with petroleum hydrocarbons. Preliminary surveys also indicate harlequins may have failed to reproduce in the spill zone in Prince William Sound during 1990. These injuries will be investigated further during 1991.

Other Birds: Surveys and studies indicate reduced numbers of black oystercatchers, pigeon guillemots, and marbled murrelets in oiled areas. Black oystercatchers and pigeon guillemots use inshore and intertidal areas for feeding and nesting. Reduced breeding success of black oystercatchers was documented in oiled areas, largely as a result of loss of chicks along oiled beaches. It is estimated that between 1,500 and 3,000 pigeon guillemots were killed by the spill, representing as much as 10 percent of the catalogued population in the Gulf of Alaska. This species is susceptible to continued exposure to petroleum hydrocarbons because it uses intertidal rocks and waters within 200 meters of shore. Petroleum hydrocarbons were found in eggs and tissue in 1989.

Marbled and Kittlitz's murrelets represented a high proportion of the dead birds recovered in oiled areas of Prince William Sound. The reduction in the number of murrelets observed in oiled areas during cleanup in 1989 and the return of many of these birds in 1990 suggest disturbance associated with cleanup activities affected these birds. The extent of injury to certain species, including loons, cormorants, and gulls will probably never be known because pre-spill information on numbers of these birds in the spill area are not available. Data on bird distribution and abundance data gathered during aerial and boat surveys remain to be fully analyzed and interpreted. Boat surveys will continue during 1991. Studies did not document injury to certain bird species such as Peale's peregrine falcons or songbirds.

FISH/SHELLFISH

No massive die-offs of adult fish were found following the spill, and adult salmon, for example, were evidently able to migrate to spawning areas after the spill. However, fish are most vulnerable to oil contamination during the early stages of their life cycles. Accordingly, most fish studies initially focused on this phase of fish life history. During 1991, scientists will begin to be able to assess affects on adult fish such as salmon that would have been exposed to oil as eggs or larvae. Species most often affected by the spill were those that inhabit and spawn in the intertidal zone (salmon) or in the shallow areas next to shore (herring and Dolly Varden).³ Less than ten dead rockfish were found during the spill and their deaths were attributed to oil. Several species of coastal and offshore fish (pollock, halibut, sablefish, cod, yellowfin and flathead sole, and rockfish) show evidence over a large geographic area of continuing exposure to petroleum hydrocarbons in areas affected by the spill, but significant injury has not yet been documented. Exposure to petroleum hydrocarbons does not necessarily lead to

³The State of Alaska imposed the highest possible standards for commercial fishery openings and for processing plant inspections to insure that all commercially harvested salmon were free from contamination. Salmon subject to commercial harvest in the spill area were rigorously tested to insure that the catch was safe for human consumption.

injury, since many animals have the capability to physiologically "manage" the exposure with no resulting harm. In particular, salmon and other fish can metabolize petroleum hydrocarbons so that these contaminants are unlikely to be found in edible fish tissues. Indicators of exposure among fish include bile metabolites and mixed function oxidases. Since injuries from chronic exposure to oil may not manifest themselves for a number of years, it is premature to conclude that coastal and offshore species were not injured; therefore certain studies are continuing.

Pink Salmon: The full extent of short term injury to pink salmon cannot be assessed until after the 1991 run returns to spawn in the summer. Although the overall catch of pink salmon in Prince William Sound during 1990 was an all-time record (as predicted before the spill), this was primarily due to strong runs of hatchery-produced salmon. Salmon survival associated with the Armin F. Koernig hatchery, located in the middle of a heavily oiled area of the spill zone, was half that of Ester Hatchery, located outside the area of the spill. Wild production of pink salmon did not mirror the record production of hatchery fish.

Seventy-five percent of wild pink salmon spawn in the intertidal portion of streams in Prince William Sound. Wild stock salmon did not shift spawning habitat following the spill and deposited eggs in intertidal areas of oiled streams. Preliminary analyses indicate a 70 percent greater mortality of pink salmon eggs laid in the summer of 1989 and a 50 percent greater mortality in the summer of 1990 in oiled streams as compared to control streams. Larvae from heavily oiled streams showed gross morphological abnormalities, including club fins and curved spines. The pink salmon that returned to Prince William Sound in the summer of 1990 were exposed to oil as larvae as they swam under the slick, but not as eggs which were more directly exposed to oil than the larvae. Fish returning in 1991 will be the first that were exposed to oil as eggs. Eggs and larvae of wild populations continue to be exposed to oil in intertidal gravel in oiled areas.

Sockeye Salmon: Commercial harvest of sockeye salmon was curtailed in portions of Cook Inlet, Chignik, and Kodiak in 1989 because of the spill, resulting in an unusually high number of adults migrating to spawn in certain lake spawning systems (returning adults that arrive at the spawning areas are referred to as the "escapement"). Overly large spawning escapements may result in poor returns in future years by producing more juvenile salmon than can be supported by the nursery lake's productivity. Preliminary data indicate that overescapement degraded rearing habitat in lakes and that sockeye salmon survival and growth rates are lower than usual. Further study is needed before the extent of these injuries can be determined.

Dolly Varden and Cutthroat Trout: Prince William Sound is the northern extreme of the range of cutthroat trout. Both cutthroat trout and Dolly Varden use nearshore and estuarine habitat for feeding throughout their lives (in contrast to salmon which migrate out to sea). The highest concentrations of bile petroleum hydrocarbon metabolites in all fish sampled were found in Dolly Varden. Tagging studies have demonstrated that the annual mortality of adult Dolly Varden was 32 percent greater in oiled areas than in unoiled areas. The larger cutthroat trout showed similar levels of mortality in oiled and unoiled areas. Additionally, cutthroat trout growth rates were reduced in oiled areas.

Studies are continuing to measure impacts on populations of these popular sport fish species.

Pacific Herring: Populations of Pacific herring were spawning in shallow eelgrass and algal beds at the time of the spill. The effects of oil on egg survival, hatching success, larval development, and recruitment to the spawning population were studied. Study results show a large increase in the percentage of abnormal embryos and larvae in oiled areas of Prince William Sound during the 1989 reproductive season. Larvae in oiled areas also had a greater incidence of eye tumors. These effects continued but at somewhat lower rates in 1990. Results also showed greater egg mortality in oiled areas as compared to unoiled areas. Whether the adult population has been affected by these larval injuries will not be determined until the 1989 and 1990 cohorts return to spawn in 1992 and 1993.

COASTAL HABITAT

The coastal tidal zone, commonly known as the "intertidal zone," was the most severely contaminated habitat. Intertidal habitats are highly productive and biologically rich. They are particularly vulnerable to the grounding of oil, its persistence, and effects of associated clean-up activities. An interdisciplinary team with expertise in plant and systems ecology, marine biology, and statistical analysis, was established to conduct field studies to assess the effects of oil on intertidal ecosystems.

Supratidal: Results of studies in the Kodiak/Alaska Peninsula area suggest that oil in the supratidal habitat and beach cleanup disturbance decreased the productivity of grasses and other vegetation including beach rye grass, that help stabilize beach berms. In one instance, cleanup activities completely removed the vegetation. Increased production of supratidal vegetation was found in Prince William Sound in 1989. This finding corresponds with information from other oil spills. It is not known whether this increased production was a result of decreased browsing by terrestrial mammals or a fertilizer effect of the oil.

Intertidal: Natural populations of intertidal organisms were significantly reduced along heavily oiled shorelines such as Herring Bay. Densities of intertidal algae (*Fucus*), barnacles, limpets, amphipods, isopods, and marine worms were decreased. Although there were increased densities of mussels in oiled areas, they were significantly smaller than mussels in the unoiled areas and the total biomass of mussels was significantly lower. Intertidal organisms continue to be exposed to hydrocarbons from the more heavily oiled sediments. Petroleum hydrocarbon accumulation in filter feeding mussels experimentally placed in oiled areas indicate that oil remains available for uptake by other organisms. Initial findings also indicate that oiled surfaces retarded settlement by juvenile barnacles when compared to unoiled sites. In addition to direct mortality, the reproductive cycle of mussels at oiled sites in the lower Cook Inlet/Kenai Peninsula and Kodiak/Alaska Peninsula regions was delayed by several months.

Intertidal fishes were less abundant in oiled areas than in unoiled areas. In addition, gill

parasitism and respiration rates were significantly higher in fish from oiled sites compared to unoiled sites.

Fucus, the dominant intertidal plant, was severely affected by the oil and subsequent cleanup activities. The percentage of intertidal areas covered by Fucus was reduced following the spill and opportunistic plant species which characteristically flourish in disturbed areas were increased. The average size of Fucus was reduced, the number of reproductive sized plants greatly decreased, and the remaining plants of reproductive size decreased in reproductive potential due to fewer fertile receptacles per plant. There was also reduced recruitment of Fucus at oiled sites.

SUBTIDAL HABITATS

Spilled oil in some areas has migrated to and contaminated the seafloor at depths of up to 100 meters as contaminated sediments moved off beaches during winter storms and cleanup activities. There is evidence that petroleum hydrocarbons have been taken up by animals feeding on the ocean bottom. Petroleum hydrocarbon metabolites have been found in the bile of yellowfin sole, rock sole, rockfish, and pollock. Concentrations of petroleum hydrocarbon metabolites in the bile of yellowfin sole have not declined from 1989 to 1990. This contrasts with Dolly Varden which feed close to shore and where petroleum hydrocarbon metabolites in bile decreased in the same period. The effects of this exposure are still being studied. Many subtidal and intertidal species, particularly fish, have the capability of metabolizing and eliminating petroleum hydrocarbons from their bodies. Clams metabolize hydrocarbons very slowly and consequently accumulated them in high concentrations.

Contaminated clams and other invertebrates are a potential continuing source of petroleum hydrocarbons for sea otters and otherspecies that forage in the shallow subtidal zone. Samples from pollock, which feed in the water column, taken as far away as 500 mile from the wreck site on Bligh Reef, showed elevated petroleum hydrocarbon metabolite concentrations in their bile. This indicates that the water column or food supply was affected at great distances from the spill. Initial 1990 study results show a significant effect on benthic organisms associated with eelgrass beds. These are known to be highly productive habitats. The composition of benthic animal communities on soft-bottom habitats as deep as 40 meters were also significantly altered in oiled areas.

ARCHAEOLOGICAL AND SUBSISTENCE RESOURCES

The spill directly impacted archaeological sites and subsistence resources. Cleanup activities and the associated significant increases in human activity throughout the spill zone resulted in additional injuries to these resources.

Archaeological Resources: Archaeological sites along the shoreline were injured by the

spill. Review of spill response data revealed injuries from oil to a minimum of 26 archaeological sites. Among these are burial sites and home sites. Twenty-one (21) of these sites are on federally-owned land, with the remaining five on State of Alaska and private lands. Of the 21 sites on federal land, 10 are on national parks, six on national wildlife refuges, four within Chugach National Forest, and one on Bureau of Land Management land. While injury to these 26 sites was documented during cleanup, a spill-wide assessment of injuries to archaeological resources has yet to be completed. In addition to oil contamination, increased knowledge of the location of archaeological sites may put them at risk from looting. Loss of rye grass cover may threaten some sites. A comprehensive survey of injuries to archaeological resources on public lands throughout the spill zone will be conducted during 1991.

A study was conducted to determine impacts caused by oil contamination on radiocarbon dating of archaeological resources and to investigate the potential for cleaning artifacts and materials to allow such dating. Preliminary results indicate significant injury to the ability to contextually date artifacts and materials by Carbon 14 analysis. It also appears that these materials cannot be successfully "cleaned" to allow accurate dating.

Subsistence Resources: Surveys undertaken by state researchers before the spill and in 1990 indicated that subsistence harvesters in the area affected by the oil spill significantly reduced their use of subsistence resources after the spill, primarily because of their concerns about possible contamination of these resources. The oil spill disrupted the subsistence lifestyle of some communities that have historically relied upon these resources. Some communities virtually or entirely ceased subsistence harvests in 1989 and have only gradually begun to resume harvests, while other communities continued some reduced level of subsistence harvest in 1989 and thereafter. The attached report (Subsistence Use of Fish and Wildlife in 15 Alutiiq Villages after the Exxon Valdez Oil Spill) details these studies. Warnings were issued by the state in 1989 for people to avoid consumption of intertidal invertebrates (such as mussels and clams, which bioaccumulate petroleum hydrocarbons) found along shorelines contaminated by oil. After the spill, an oil spill health task force was formed, including the state and federal governments, subsistence users, and Exxon. This group helped oversee studies conducted by the state and others in conjunction with FDA and NOAA in 1989 and 1990, on subsistence food resources such as seals, deer, salmon, ducks, clams, and bottomfish. Based upon the test results these resources, with the exception of clams and mussels in certain oiled areas such as Windy Bay, were determined to be safe for human consumption.

CONCLUSION

The federal and state Trustee agencies have now concluded two field seasons of study and are currently preparing to begin a third year of studies to assess injuries to natural resources resulting from the Exxon Valdez oil spill. The information contained in this

summary is based upon the field work and data analysis conducted to date, and is preliminary. Many studies will likely need to continue for additional years before a full understanding of injuries is developed. For example, long-lived species such as bald eagles, murre, and sea otters, may not manifest some effects until a number of years have passed. For other species, such as herring and salmon that return to spawn years after hatching, it is necessary to wait for these key life history events to occur before one can determine the extent to which or if they have been injured. At present there is no indication of long-term injury for species other than those noted in this summary. Although two field seasons of study are complete, only a portion of the data gathered has been fully analyzed and interpreted. As studies and data analysis are completed, some of the information contained in this summary may need to be modified.

For the reasons given above, injury assessment studies will continue in 1991, and thereafter until the process is complete. The need to continue to understand the long-term effects of the spill will be accomplished through monitoring projects that will measure the natural recovery of resources injured by the spill as well as the effectiveness of restoration measures implemented by the Trustee agencies. The information gathered by the injury assessment studies, the restoration monitoring studies, and other studies will be used to develop and implement a restoration program that will accelerate the recovery of injured resources.

Restoration measures will begin in 1991 and are expected to become more comprehensive as the understanding of the effects of the spill improves and as experts and the public provide input on where restoration measures should be concentrated. Wherever possible, restoration will focus on those projects that will provide ecosystem-wide benefits, thereby benefitting a variety of species. These projects may include various initiatives to protect habitat; in other cases it may be necessary to conduct restoration programs that will primarily benefit a particular resource injured by the spill.

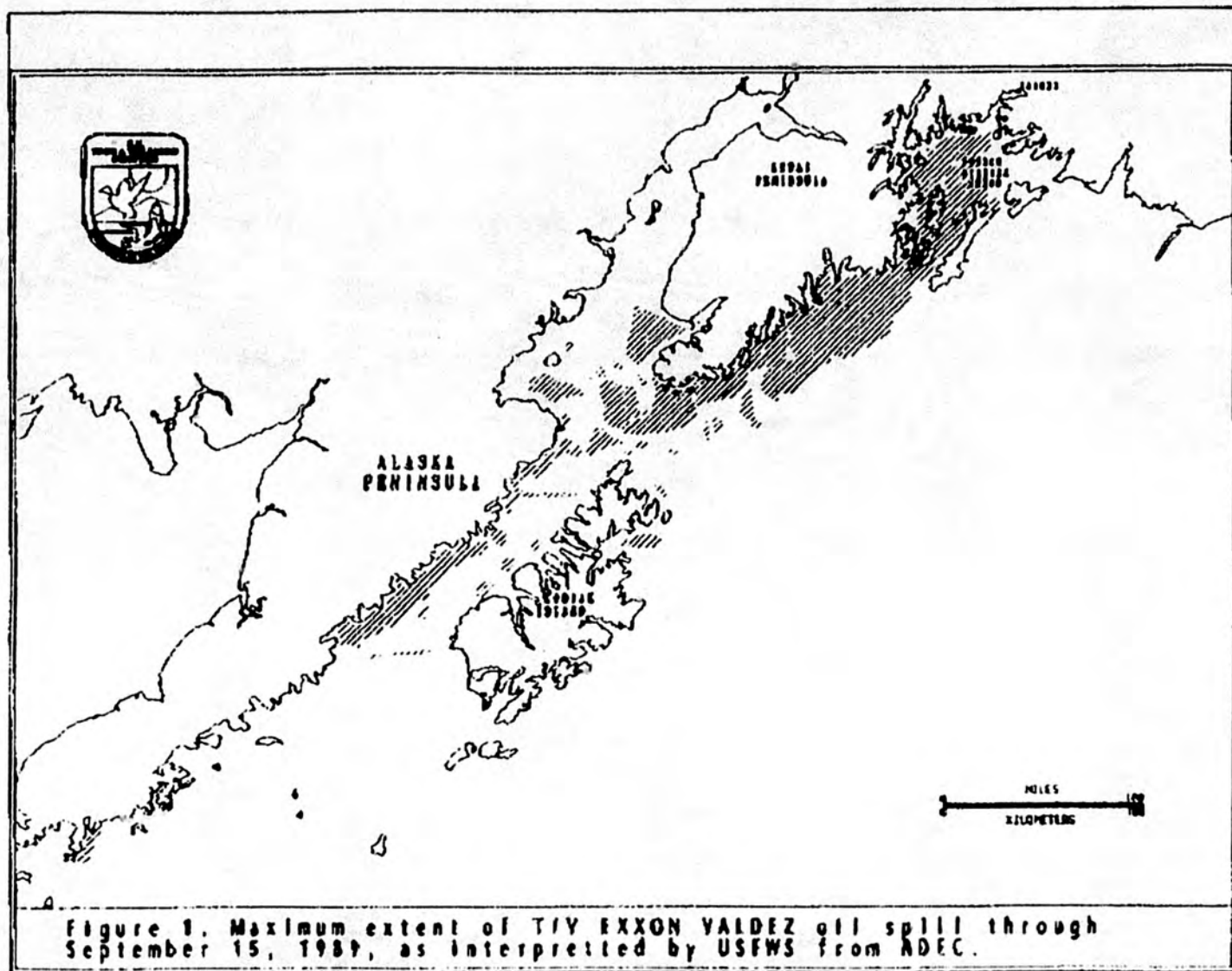


Table 1. Species composition and number of birds retrieved from oiled areas and processed at U.S. Fish and Wildlife receiving stations as of 25 September, 1989.

Species	Total	Valdez	Seward	Homer	Kodiak
Total	35,279	3,360	3,503	5,778	22,638
Unidentified bird	2,927	476	414	916	1,131
Unidentified loon	69	27	6	25	11
Common Loon	216	142	23	32	19
Yellow-billed Loon	87	72	5	3	7
Pacific Loon	18	8	5	0	5
Red-throated Loon	5	3	1	1	0
Unidentified grebe	65	27	8	11	19
Red-necked Grebe	120	79	22	12	7
Horned Grebe	277	233	15	22	7
Northern Fulmar	426	0	22	12	116
Unidentified shearwater	579	5	22	14	538
Sooty Shearwater	360	4	80	34	242
Short-tailed Shearwater	2,460	1	84	4	2,371
Unidentified petrel	69	2	24	14	29
Fork-tailed Storm-petrel	363	1	50	19	293
Leach's Storm-petrel	12	0	9	0	3
Unidentified cormorant	219	76	27	56	60
Double-crested Cormorant	38	19	10	0	9
Pelagic Cormorant	418	277	65	29	47
Red-faced Cormorant	161	90	29	9	33
Great Blue Heron	1	1	0	0	0
Unidentified swan	3	0	2	1	0
Emperor Goose	2	0	0	0	2
Canada Goose	1	0	0	1	0
Brant	3	0	1	2	0
Unidentified duck	30	4	6	20	0
Unidentified seaduck	112	63	2	11	36
Mallard	11	2	4	1	4
Northern Pintail	4	0	3	1	0
Green-winged Teal	5	0	5	0	0
Unidentified Scaup	4	1	3	0	0
Greater Scaup	27	2	21	4	0
Lesser Scaup	2	0	2	0	0
Unidentified Goldeneye	25	8	2	14	1
Common Goldeneye	6	3	0	2	1
Barrow's Goldeneye	33	19	9	4	1
Bufflehead	21	17	1	0	3
Oldsquaw	185	131	43	6	5

Table 1. Species composition and number of birds retrieved from oiled areas and processed at U.S. Fish and Wildlife receiving stations as of 25 September, 1989. (Cont'd)

Species	Total	Valdez	Seward	Homer	Kodiak
Harlequin Duck	213	148	10	35	20
Unidentified Eider	3	0	0	3	0
Stellar's Eider	4	4	0	0	0
Common Eider	17	5	0	2	10
King Eider	9	0	0	0	9
Unidentified Scoter	162	23	17	51	71
White-winged Scoter	342	164	13	137	23
Surf Scoter	175	45	28	9	6
Black Scoter	132	112	4	8	8
Ruddy Duck	1	0	1	0	0
Unidentified merganser	3	1	0	0	2
Common Merganser	2	2	0	0	0
Red-breasted Merganser	33	30	1	1	1
Sandhill Crane	2	1	1	0	0
Black Oystercatcher	9	2	2	0	5
Golden Plover	1	0	0	1	0
Unidentified sandpiper	11	1	5	1	4
Unidentified turnstone	1	0	0	0	1
Common Snipe	1	0	0	1	0
Semipalmated Sandpiper	1	0	1	0	0
Lesser Yellowlegs	2	0	0	2	0
Western Sandpiper	5	0	0	5	0
Baird's Sandpiper	1	0	0	0	1
Least Sandpiper	4	0	2	0	2
Surfbird	3	3	0	0	0
Short-billed Dowitcher	1	0	0	0	1
Red Phalarope	2	0	0	2	0
Red-necked Phalarope	7	1	3	0	3
Long-tailed Jaeger	1	0	0	0	1
Unidentified gull	99	6	34	39	20
Glaucous-winged Gull	555	33	188	28	213
Herring Gull	8	3	5	0	0
Mew Gull	33	0	3	3	27
Black-legged Kittiwake	1,225	8	214	74	929
Arctic Tern	3	1	1	0	1
Aleutian Tern	1	0	0	0	1

CACI FILMED

Table 1. Species composition and number of birds retrieved from oiled areas and processed at U.S. Fish and Wildlife receiving stations as of 25 September, 1989. (Cont'd)

Species	Total	Valdez	Seward	Homer	Kodiak
Unidentified alcid	173	24	0	15	134
Unidentified murre	8,851	21	775	2,101	5,954
Common Murre	10,428	399	523	1,353	3,153
Thick-billed Murre	669	16	142	73	438
Pigeon Guillemot	614	136	109	153	214
Unidentified murrelet	413	21	37	121	234
Marbled Murrelet	612	289	97	82	144
Kittlitz's Murrelet	67	23	19	21	4
Ancient Murrelet	311	3	40	73	195
Cassin's Auklet	48	0	36	2	10
Least Auklet	5	0	0	1	4
Parakeet Auklet	31	1	2	1	27
Rhinoceros Auklet	141	0	31	31	79
Unidentified puffin	46	0	7	4	35
Horned Puffin	139	0	32	13	94
Tufted Puffin	361	0	29	15	317
Bald Eagle	125	31	20	15	59
Unidentified raptor	7	1	3	2	1
Peregrine Falcon	2	0	0	0	2
Willow Ptarmigan	1	0	0	0	1
Unidentified owl	1	0	0	1	0
Great-horned Owl	3	0	0	3	0
Unidentified woodpecker	1	0	0	1	0
Cliff Swallow	3	0	3	0	0
Violet-green Swallow	1	0	1	0	0
Unidentified passerine	9	1	7	1	0
Stellar's Jay	1	1	0	0	0
Magpie	7	1	0	0	6
Common Raven	18	1	4	0	13
Northwestern Crow	34	6	3	3	22
American Robin	2	0	2	0	0
Varied Thrush	1	0	0	0	1
Hermit Thrush	1	0	1	0	0
Unidentified warbler	1	0	0	0	1
Yellow Warbler	3	0	3	0	0
Pine Grosbeak	1	0	0	0	1
Unidentified sparrow	15	0	10	2	3
Savannah Sparrow	1	0	1	0	0
Golden-crowned Sparrow	4	0	3	0	1
White-winged Crossbill	8	0	0	6	2

BARRY M. HARTMAN
Acting Assistant Attorney General
Environment & Natural Resources
Division

STUART M. GERSON
Assistant Attorney General
Civil Division
U.S. Department of Justice
Washington, D.C. 20530

Attorneys for Plaintiff United States of America

CHARLES E. COLE
Attorney General
State of Alaska
Pouch K
Juneau, Alaska 99811

Attorney for Plaintiff State of Alaska

Deb
File
EXXON VALDEZ
SETTLEMENT
H

SEP 30 1991

FILED

OCT 09 1991

UNITED STATES DISTRICT COURT
DISTRICT OF ALASKA
JEL *Deputy*

UNITED STATES DISTRICT COURT
DISTRICT OF ALASKA

UNITED STATES OF AMERICA,
Plaintiff,

v.

EXXON CORPORATION, EXXON SHIPPING
COMPANY, and EXXON PIPELINE COMPANY,
in personam, and the T/V
EXXON VALDEZ, in rem,
Defendants.

Civil Action No.
A91-082 CIV

STATE OF ALASKA,
Plaintiff,

v.

EXXON CORPORATION, and EXXON
SHIPPING COMPANY,
Defendants.

Civil Action No.
A91-083 CIV

AGREEMENT AND CONSENT
DECREE

ACE 7228191

- 2 -

AGREEMENT AND CONSENT DECREE

This Agreement and Consent Decree (the "Agreement") is made and entered into by the United States of America and the State of Alaska ("State") (collectively referred to as the "Governments"), Exxon Corporation and Exxon Shipping Company ("Exxon Shipping") (collectively referred to, together with the T/V EXXON VALDEZ, as "Exxon"), and Exxon Pipeline Company ("Exxon Pipeline").

Introduction

On the night of March 23-24, 1989, the T/V EXXON VALDEZ, owned by Exxon Shipping, went aground on Bligh Reef in Prince William Sound, Alaska. As a result of the grounding, several of the vessel's cargo tanks ruptured and approximately 11 million gallons of crude oil owned by Exxon Corporation spilled into Prince William Sound (the "Oil Spill").

The State has filed an action in the Superior Court for the State of Alaska, Third Judicial District, arising from the Oil Spill, identified as State of Alaska v. Exxon Corporation, et al., Civil No. 3AN-89-6852 ("State Court Action"), and Exxon has asserted counterclaims against the State in that action.

On March 13, 1991 and March 15, 1991, respectively, the United States and the State each filed a complaint in this Court against Exxon and Exxon Pipeline, asserting civil claims relating to or arising from the Oil Spill ("Federal Court Complaints"). Exxon and Exxon Pipeline have asserted counterclaims against the

ACE 7228192

- 3 -

United States and the State in their responses to the Federal Court Complaints.

The United States and the State represent that it is their legal position that only officials of the United States designated by the President and state officials designated by the Governors of the respective states are entitled to act on behalf of the public as trustees of Natural Resources to recover damages for injury to Natural Resources arising from the Oil Spill under Section 311(f) of the Clean Water Act, 33 U.S.C. § 1321(f).

Exxon represents that, during the period from the Oil Spill through August, 1991, it expended in excess of \$2.1 billion for clean-up activities and reimbursements to the federal, State, and local governments for their expenses of response to the Oil Spill.

The Parties recognize that the payments called for in this Agreement are in addition to those described above, are compensatory and remedial in nature, and are made to the Governments in response to their pending or potential civil claims for damages or other civil relief against Exxon and Exxon Pipeline arising from the Oil Spill.

NOW, THEREFORE, the Parties agree, and it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

Jurisdiction

1. The Court has jurisdiction over the subject matter of the claims set forth in the Federal Court Complaints and over the parties to this Agreement pursuant to, among other authorities,

28 U.S.C. §§ 1331, 1333 and 1345, and section 311(f) of the Clean Water Act, 33 U.S.C. § 1321(f). This Court also has personal jurisdiction over Exxon and Exxon Pipeline, which, solely for the purposes of this Agreement, waive all objections and defenses that they may have to the jurisdiction of the Court or to venue in this District.

Parties

2. "United States" means the United States of America, in all its capacities, including all departments, divisions, independent boards, administrations, natural resource trustees, and agencies of the federal government.

3. "State" means the State of Alaska, in all its capacities, including all departments, divisions, independent boards, administrations, natural resource trustees, and agencies of the state government.

4. "Exxon" means Exxon Corporation, a New Jersey corporation, Exxon Shipping Company, a Delaware corporation, and the T/V EXXON VALDEZ, Official Number 692966 (now the T/V EXXON MEDITERRANEAN).

5. "Exxon Pipeline" means Exxon Pipeline Company, a Delaware corporation.

Definitions

6. Whenever the following capitalized terms are used in this Agreement, they shall have the following meanings:

(a) "Alyeska" means Alyeska Pipeline Service Company, a

Delaware corporation, its shareholders and owner companies, and its present and former shareholder representatives.

(b) The "TAPL Fund" means the Trans-Alaska Pipeline Liability Fund, a federally chartered corporation organized and existing under the laws of the State of Alaska.

(c) "Natural Resources" means land, fish, wildlife, biota, air, water, ground water, drinking water supplies, and other such resources belonging to, managed by, held in trust by, appertaining to, or otherwise controlled by the United States (including the resources of the fishery conservation zone established by the Magnuson Fishery Conservation and Management Act of 1976, 16 U.S.C. §§ 1801 et seq.), the State, or both the United States and the State.

(d) "Natural Resource Damages" means compensatory and remedial relief recoverable by the Governments in their capacity as trustees of Natural Resources on behalf of the public for injury to, destruction of, or loss of any and all Natural Resources resulting from the Oil Spill, whether under the Clean Water Act, 33 U.S.C. §§ 1251, et seq., the Trans-Alaska Pipeline Authorization Act, 43 U.S.C. §§ 1651, et seq., or any federal or state statute or maritime or common law relating to the environment, including (1) costs of damage assessment, (2) compensation for loss, injury, impairment, damage or destruction of Natural Resources, whether temporary or permanent, or for loss of use value, non-use value, option value, amenity value, bequest value, existence value, consumer surplus, economic rent, or any

similar value of Natural Resources, and (3) costs of restoration, rehabilitation or replacement of injured Natural Resources or the acquisition of equivalent resources.

(e) "Party" or "Parties" means Exxon, Exxon Pipeline, the United States, and the State, or any of them.

(f) "Trustees" means the Secretaries of the U.S. Departments of Agriculture and the Interior, the Administrator of the National Oceanic and Atmospheric Administration, U.S. Department of Commerce, the Alaska Attorney General, and the Commissioners of the Alaska Departments of Environmental Conservation and Fish and Game.

(g) The "Oil Spill" means the occurrence described in the first paragraph of the Introduction above, and all consequences proximately caused by or arising from the Oil Spill, including, without limitation, response, cleanup, damage assessment and restoration activities.

(h) "Effective Date" shall mean the earliest date on which all Parties have signed this Agreement.

(i) "Final Approval" shall mean the earliest date on which all of the following have occurred: (1) the Court has approved and entered the Agreement as a judgment, without modification and without interpreting a material term of the Agreement, prior to or at the time of approval, in a manner inconsistent with the Parties' intentions; and (2) the time for appeal from that judgment has expired without the filing of an appeal, or the judgment has been upheld on appeal and either the

time for further appeal has expired without the filing of a further appeal or no further appeal is allowed.

Effect of Entry of Decree by Court

7. Upon approval and entry of this Agreement by the District Court, this Agreement and Consent Decree shall constitute a final judgment between the Governments and Exxon and Exxon Pipeline in accordance with its terms.

Payment Terms

8. Exxon shall pay to the Governments pursuant to this Agreement a total of \$900 million, discharged as follows:

(a) Exxon shall pay, within 10 days after the Effective Date, \$90,000,000.

(b) Exxon shall pay on December 1, 1992 the amount determined by the following formula:

amount payable = \$150,000,000 minus X, where
"X" equals Exxon's expenditures for work done from January 1, 1991 through March 12, 1991, in preparation for and conduct of clean-up of the Oil Spill in accordance with directions of the Federal On-Scene Coordinator, up to a maximum of \$4,000,000, plus Expenditures made by Exxon for clean-up work after March 12, 1991 in accordance with Paragraph 11; provided that all such Expenditures shall be subject to audit by the Governments.

(c) Exxon shall pay each of the amounts specified in the following schedule by the dates set forth in that schedule:

- 8 -

September 1, 1993	\$100,000,000
September 1, 1994	\$ 70,000,000
September 1, 1995	\$ 70,000,000
September 1, 1996	\$ 70,000,000
September 1, 1997	\$ 70,000,000
September 1, 1998	\$ 70,000,000
September 1, 1999	\$ 70,000,000
September 1, 2000	\$ 70,000,000
September 1, 2001	\$ 70,000,000

(d) The payments required by this paragraph shall be made as directed jointly in writing, not less than 5 business days before the due date, by the Assistant Attorney General, Environment & Natural Resources Division, United States Department of Justice, and the Attorney General, State of Alaska.

9. If Final Approval has not occurred by the date a payment required under Paragraph 8 is due, Exxon shall, on or before that date, deposit the amount of the payment into an interest-bearing trust account (the "Escrow") in a federally chartered bank ("Escrow Agent)". The Escrow agreement between Exxon and the Escrow Agent shall provide that the Escrow Agent shall submit to the jurisdiction and venue of the United States District Court for the District of Alaska in connection with any litigation arising out of that Escrow agreement. Exxon shall notify the Governments promptly in writing of any deposit of a payment due under this Agreement into the Escrow. Upon Final Approval and within five (5) business days of receipt of written instructions as to payment signed jointly by the Assistant Attorney General, Environment & Natural Resources Division, United States Department of Justice, and the Attorney General, State of Alaska, Exxon shall require that a sum be paid to the Governments equal

ACE 7228198

- 9 -

to all amounts required to be paid into the Escrow pursuant to this paragraph together with an amount calculated by applying to each deposit a rate equal to the average daily yield on three-month Treasury Bills in effect while the funds are on deposit. "The average daily yield on three-month Treasury Bills" means the arithmetic mean of the three-month Treasury Bill rates, as quoted in the H.15 (519) weekly release published by the Board of Governors of the Federal Reserve System under the caption "U.S. Government Securities/Treasury Bills/Secondary Market," multiplied by the actual number of days of such deposit divided by 360. For the purposes of calculating such arithmetic mean, each Saturday, Sunday and holiday shall be deemed to have a rate equal to the rate for the immediately preceding business day. If the earnings accrued on the Escrow are insufficient to make the payment to Governments required by this paragraph and to pay the reasonable fees and expenses of the Escrow Agent, Exxon shall pay the difference so that such amounts will be paid in full. No amount shall be disbursed from the Escrow for any reason, except to make the payment required by this paragraph or to pay reasonable fees and expenses of the Escrow Agent and, after the foregoing payments, to close out the Escrow, unless any Party terminates the Agreement pursuant to Paragraph 37. If the Agreement is terminated, all sums in the Escrow shall be returned to Exxon.

10. As agreed to between the Governments, without any consultation with or participation by Exxon or Exxon Pipeline,

ACE 7228199

the amounts paid under Paragraphs 8 or 9 shall be applied by the Governments solely for the following purposes: (1) to reimburse the United States and the State for response and clean-up costs incurred by either of them on or before December 31, 1990 in connection with the Oil Spill; (2) to reimburse the United States and the State for natural resource damages assessment costs (including costs of injury studies, economic damages studies, and restoration planning) incurred by either of them on or before March 12, 1991 in connection with the Oil Spill; (3) to reimburse the State for attorneys fees, experts' fees, and other costs (collectively, "Litigation Costs") incurred by it on or before March 12, 1991 in connection with litigation arising from the Oil Spill; (4) to reimburse the United States and the State for response and clean-up costs incurred by either of them after December 31, 1990 in connection with the Oil Spill; and (5) to reimburse or pay costs incurred by the United States or the State or both after March 12, 1991 to assess injury resulting from the Oil Spill and to plan, implement, and monitor the restoration, rehabilitation, or replacement of Natural Resources, natural resource services, or archaeological sites and artifacts injured, lost, or destroyed as a result of the Oil Spill, or the acquisition of equivalent resources or services; and (6) to reimburse the State for reasonable Litigation Costs incurred by it after March 12, 1991.) The aggregate amount allocated for United States past response and clean-up costs and damage assessment costs (under items 1 and 2 above) shall not exceed \$67.

million, and the aggregate amount allocated for State past response and clean-up costs, damage assessment costs, and Litigation Costs incurred on or before March 12, 1991 (under items 1-3 above) shall not exceed \$75 million. The amounts allocated for State Litigation Costs incurred after March 12, 1991 (under item 6 above) shall not exceed \$1 million per month. The Governments represent that the monies paid by Exxon to the Governments pursuant to this Agreement will be allocated, received, held, and used in accordance with the Memorandum of Agreement and Consent Decree between the United States and the State of Alaska ("MOA"), which this Court entered on August 28, 1991, in United States v. State of Alaska, Civil Action No. A91-081 CV. This paragraph and the MOA do not create any rights in, or impose any obligations on, Exxon, Exxon Pipeline, Alyeska, or any other person or entity except the Governments.

Commitment by Exxon to Continue Clean-up

11. (a) Exxon shall continue clean-up work relating to the Oil Spill after the Effective Date, as directed by and in accordance with the directions of the Federal On-Scene Coordinator ("FOSC"), subject to prior approval by the FOSC of the costs of work directed by the FOSC. After the Effective Date, Exxon shall also perform any additional clean-up work directed by the State On-Scene Coordinator ("State OSC") that does not interfere or affirmatively conflict with work directed by the FOSC or with federal law, in accordance with the directions of, and subject to prior approval of costs by, the

- 12 -

State OSC. If Exxon concludes that work directed by the State OSC would interfere or affirmatively conflict with work directed by the FOSC, or with federal law, it shall promptly notify the State OSC and the FOSC of the potential conflict and shall not be required to proceed with the work directed by the State OSC until the FOSC or the Court determines that there is no conflict or that any potential conflict has been eliminated, and directs Exxon how to proceed. Exxon should have no liability to any person or entity, including the Governments, by reason of undertaking clean-up work performed in accordance with directions of the FOSC or the State OSC.

(b) Upon Final Approval, Exxon shall have no further obligations with respect to clean-up of the Oil Spill except as set forth in this Agreement and in addition Exxon shall be entitled to a credit, to be applied to the next payment due from Exxon to the Governments, as provided in subparagraph 8(b), for all Expenditures incurred by Exxon for clean-up work pursuant to directions of the FOSC or the State OSC in accordance with subparagraph 11(a). As used in this paragraph, and in subparagraph 8(b) and Paragraph 12, "Expenditures" shall include, without limitation, costs and obligations incurred for salary, wages, benefits, and expenses of Exxon employees, for contractors, for equipment purchase and rental, for office and warehouse space, and for insurance, accounting, and other professional services.

ACE 7228202

12. If this Agreement is terminated pursuant to Paragraph 37 below, or if a final judicial determination is made that this Agreement will not be approved and entered, Exxon shall be entitled to set off against any liability it may have to either Government arising from the Oil Spill the amount of any Expenditures made by Exxon for clean-up work directed by the FOSC or the State OSC under Paragraph 11(a), if the work meets the following criteria:

(a) if total Expenditures incurred by Exxon for clean-up after the Effective Date are \$35 million or less, Expenditures for work shall be set-off if Exxon shows both --

(1) that based on the information available at the time to the FOSC or State OSC who directed the work, the anticipated cost of the work was grossly disproportionate to the net environmental benefits reasonably anticipated from the work, or the work could not reasonably have been expected to result in a net environmental benefit; and

(2) that a reasonable time before beginning to perform the work, Exxon submitted a written objection to the work to the FOSC or State OSC who directed the work, requesting reconsideration of the work directions on one of the grounds set forth in subparagraph 12(a)(1) above; or

(b) if total Expenditures by Exxon for clean-up after the Effective Date exceed \$35 million, Expenditures for work shall be set-off unless the Government or Governments against

which Exxon is seeking to assert the set-off provided by this paragraph show that, based on the information available at the time to the FOSC or State OSC who directed the work, the work was reasonably expected to result in a net environmental benefit, and the anticipated cost of the work was not substantially out of proportion to the net environmental benefit reasonably anticipated from the work.

Releases and Covenants Not to Sue by the Governments

13. Effective upon Final Approval, the Governments release and covenant not to sue or to file any administrative claim against Exxon with respect to any and all civil claims, including claims for Natural Resource Damages, or other civil relief of a compensatory and remedial nature which have been or may be asserted by the Governments, including without limitation any and all civil claims under all federal or state statutes and implementing regulations, common law or maritime law, that arise from, relate to, or are based on, or could in the future arise from, relate to, or be based on: (1) any of the civil claims alleged in the pending action against Exxon by the State in the State Court Action, (2) any of the civil claims asserted in the Federal Court Complaints, or (3) any other civil claims that could be asserted by either or both of the Governments against Exxon relating to or arising from the Oil Spill; provided, however, that nothing in this Agreement shall affect or impair the following:

ACE 7228204

- 15 -

(a) claims by either Government to enforce this Agreement, including without limitation Exxon's agreement to make additional payments as set forth in Paragraphs 17-19;

(b) claims by the State for tax revenues which would have been or would be collected under existing AS 43.75 (Fisheries Business Tax) but for the Oil Spill, provided that, if the State obtains a judgment for such a claim against Exxon or Exxon Pipeline, the State will enforce against Exxon or Exxon Pipeline only that part of the judgment that would be refunded to local governments under AS 43.75.130 had the amount recovered been paid as taxes under AS 43.75;

(c) exclusively private claims, if any, by Alaska Native Villages and individual Alaska Natives, other than claims for Natural Resource Damages, seeking damages for private harms to Native subsistence well being, community, culture, tradition and way of life resulting from the Oil Spill, including private claims for private harms to Alaska Native Villages and individual Alaska Natives resulting from the impairment, destruction, injury or loss of Natural Resources caused by the Oil Spill and any other exclusively private claims that are available to Alaska Native Villages and individual Alaska Natives; and

(d) exclusively private claims, if any, by Alaska Native Corporations, other than claims for Natural Resource Damages, seeking damages for private harms resulting from injuries caused by the Oil Spill to lands in which a Native Corporation holds any present right, title, or interest, including private claims for

ACE 7228205

lost or diminished land values, for preservation, protection and restoration of archaeological or cultural resources and archaeological sites found on the lands described in this subparagraph, for private harms resulting from injuries to Natural Resources found on lands described in this subparagraph, for impairment of riparian or littoral rights, if any, and any other claims that are available to Alaska Native Corporations as private landowners; provided, however, that such claims shall not include any claims based upon injuries to tidelands or submerged lands.

14. Effective upon Final Approval, except insofar as Exxon Pipeline is liable to the Governments, or either of them, for claims relating to or arising from the Oil Spill as a result of its ownership interest in, participation in, or responsibility for Alyeska, each of the Governments provides to Exxon Pipeline covenants not to sue identical to the covenants not to sue provided to Exxon in Paragraph 13. This paragraph shall not be construed as a release or covenant not to sue given by either Government to Alyeska.

15. Effective upon the Effective Date, each of the Governments covenants not to sue any present or former director, officer, or employee of Exxon or Exxon Pipeline with respect to any and all civil claims, including Natural Resource Damages, or other civil remedies of a compensatory or remedial nature which have been or may be asserted by the Governments, including without limitation any and all civil claims under all federal or

state statutes and implementing regulations, common law or maritime law, that arise from, relate to, or are based on, or could in the future arise from, relate to, or be based on the Oil Spill; provided, however, that if any such present or former director, officer, or employee brings any action against the Governments, or either of them, for any claim whatsoever arising from or relating to the Oil Spill (or if an action against the Governments is pending at the time of Final Approval, and the director, officer, or employee fails to dismiss the action within 15 days of Final Approval), this covenant not to sue shall be null and void with respect to the director, officer, or employee bringing such action. In the event either Government obtains a judgment against any present or former director, officer, or employee of Exxon or Exxon Pipeline for liability relating to or arising from the Oil Spill, the Governments shall enforce the judgment only to the extent that the individual or individuals against whom the judgment was obtained are able to satisfy the judgment, without indemnification by Exxon or Exxon Pipeline, personally or through insurance policies purchased by the individual or individuals.

16. (a) Not later than 15 days after Final Approval, each of the claims asserted by the State against Exxon and Exxon Pipeline, except for the claim described in Paragraph 13(d) of this Agreement, and each of the claims asserted by Exxon or Exxon Pipeline against the State, in the State Court Action will be dismissed with prejudice and without an award of costs or

- 18 -

attorneys fees to any Party. Exxon, Exxon Pipeline, and the State shall enter into and execute all Stipulations of Dismissal, with prejudice, necessary to implement this subparagraph.

(b) Not later than 15 days after Final Approval, each of the claims asserted by the United States and the State against Exxon or Exxon Pipeline in the Federal Court Complaints, except for the claim described in Paragraph 13(d) of this Agreement, each of the counterclaims asserted by Exxon and Exxon Pipeline against the United States or the State in their responses to the Federal Court Complaints, shall be dismissed with prejudice and without an award of costs or attorneys fees to any Party. Exxon, Exxon Pipeline, the United States, and the State shall enter into and execute all Stipulations of Dismissal, with prejudice, necessary to implement this subparagraph.

(c) Each of the claims asserted by Exxon against the Governments or their officials in Exxon Shipping Company, et al. v. Lujan, et al., Civil Action No. A91-219 CIV (D. Alaska) ("Lujan") shall be dismissed with prejudice, and without an award of attorneys fees or costs to any Party, not later than 5 days after United States District Court approval of any agreement(s) between the Governments and the non-Government defendants in Lujan under which all of the non-Government defendants disclaim any right to recover Natural Resource Damages.

Reopener For Unknown Injury

17. Notwithstanding any other provision of this Agreement, between September 1, 2002, and September 1, 2006, Exxon shall pay

ACE 7228208

to the Governments such additional sums as are required for the performance of restoration projects in Prince William Sound and other areas affected by the Oil Spill to restore one or more populations, habitats, or species which, as a result of the Oil Spill, have suffered a substantial loss or substantial decline in the areas affected by the Oil Spill; provided, however, that for a restoration project to qualify for payment under this paragraph the project must meet the following requirements:

- (a) the cost of a restoration project must not be grossly disproportionate to the magnitude of the benefits anticipated from the remediation; and
- (b) the injury to the affected population, habitat, or species could not reasonably have been known nor could it reasonably have been anticipated by any Trustee from any information in the possession of or reasonably available to any Trustee on the Effective Date.

18. The amount to be paid by Exxon for the restoration projects referred to in Paragraph 17 shall not exceed \$100,000,000.

19. The Governments shall file with Exxon, 90 days before demanding any payment pursuant to Paragraph 17, detailed plans for all such restoration projects, together with a statement of all amounts they claim should be paid under Paragraph 17 and all information upon which they relied in the preparation of the restoration plan and the accompanying cost statement.

Releases and Covenants Not To Sue by Exxon and Exxon Pipeline

20. Effective upon Final Approval, Exxon and Exxon Pipeline release, and covenant not to sue or to file any administrative claim against, each of the Governments and their employees with respect to any and all claims, including without limitation claims for Natural Resource Damages and cleanup costs, under federal or state statutes and implementing regulations, common law, or maritime law, that arise from, relate to, or are based on or could in the future arise from, relate to, or be based on: (1) any of the civil claims asserted by either of them against the State in the State Court Action, (2) any civil claims asserted by Exxon or Exxon Pipeline against either Government in their responses to the Federal Court Complaints, or (3) any other civil claims that have been or could be asserted by Exxon or Exxon Pipeline against either of the Governments relating to or arising from the Oil Spill, except that nothing in this Agreement shall affect or impair the rights of Exxon and Exxon Pipeline to enforce this Agreement. This paragraph shall not be construed as a release or covenant not to sue given by Alyeska (including its shareholders and owner companies other than Exxon Pipeline) to the Governments.

Trans-Alaska Pipeline Liability Fund

21. The release in Paragraph 20 shall not be construed to bar any claim by Exxon against the TAPL Fund relating to or arising from the Oil Spill. If the TAPL Fund asserts any claims against the Governments that are based upon subrogation rights arising

ACE 7228210

against all Exxon Defendants, including Exxon Pipeline (which has a 20.34% participation in Alyeska), and in consideration of Exxon's obligations hereunder, the Governments agree that if either recovers any amount from Alyeska for any claim of any kind relating to or arising from the Oil Spill (such as asserted in the State Court Action against Alyeska), each Government so recovering shall instruct Alyeska to pay to Exxon, and shall take other reasonable steps to ensure that Exxon receives, 20.34% of the amount due to that Government from Alyeska.

24. Exxon and Exxon Pipeline agree that, if Alyeska receives any amount from the Governments for any claim of any kind relating to or arising from the Oil Spill, except for an amount indemnified by Exxon under Paragraph 22 or 25, Exxon and/or Exxon Pipeline shall promptly pay to the Government against which judgment is entered 20.34% of such amount.

25. If Alyeska successfully asserts claims, if any, against the Governments, or either of them, that are based upon Alyeska's own damages or losses, or upon third party contribution or subrogation rights, or other theories of recovery over, arising from Alyeska's liability to persons other than Exxon or Exxon Pipeline relating to the Oil Spill, Exxon shall indemnify the Governments for any sums paid by either of them to Alyeska based on such claims; provided that the Governments shall assert in good faith all defenses the Governments may have to such claims by Alyeska, and provided further that no indemnity shall be provided under this paragraph if the Governments refuse a good

faith proposal for a monetary settlement of such claims agreed to by Exxon and Alyeska, under which Alyeska shall fully release the Governments in exchange for a payment by or other consideration from Exxon, on behalf of the Governments, to Alyeska.

Third Party Litigation

26. (a) Except as provided in subparagraph (b) of this paragraph, if any person or entity not a party to this Agreement ("Third Party") asserts a claim relating to or arising from the Oil Spill in any present or future litigation against Exxon or Exxon Pipeline and the Governments, or against Exxon or Exxon Pipeline and either the United States or the State, each of the sued Parties ("Sued Parties") shall be responsible for and will pay its share of liability, if any, as determined by the proportional allocation of liability contained in any final judgment in favor of such Third Party, and no Sued Party shall assert a right of contribution or indemnity against any other Sued Party. However, notwithstanding any other provision of this Agreement, the Sued Parties may assert any claim or defense against each other necessary as a matter of law to obtain an allocation of liability among the Sued Parties in a case under this paragraph. Any such actions between the Sued Parties shall be solely for the purpose of allocating liability, if any. The Sued Parties shall not enforce any judgment against each other in such cases.

(b) If any person or entity, other than the TAPL Fund or Alyeska, asserts claims against the Governments, or either of

- 24 -

them, that are based upon contribution or indemnity or any other theory of recovery over against the Governments arising from any liability of or payment by said person or entity to Exxon or Exxon Pipeline relating to or arising from the Oil Spill, or based upon subrogation rights arising from any monies paid to Exxon or Exxon Pipeline, Exxon shall indemnify and hold the Governments harmless from any liability that the Governments have to such person or entity based on such claims. The foregoing indemnity (i) shall not be enforceable with respect to any amount in excess of value actually received by Exxon or Exxon Pipeline, and (ii) shall be enforceable only if the Governments assert in good faith all defenses they may have to such claims.

27. Neither Exxon nor Exxon Pipeline shall assert any right of contribution or indemnity against either Government in any action relating to or arising from the Oil Spill where that respective Government is not a party. Neither Government shall assert any right of contribution or indemnity against Exxon or Exxon Pipeline in any action relating to or arising from the Oil Spill where Exxon and Exxon Pipeline, respectively, are not parties, except that either Government may assert against Exxon the rights to indemnification as expressly provided in Paragraphs 21, 22, and 25.

28. Any liability which Exxon incurs as a result of a suit by a Third Party, as described in Paragraphs 26 or 27, shall not be attributable to or serve to reduce the payments required to be

paid by Exxon pursuant to Paragraph 8 or any additional payment required under Paragraph 17.

29. The Parties agree that they will not tender each other to any Third Party as direct defendants in any action pursuant to Rule 14(c) of the Federal Rules of Civil Procedure.

30. If a Third Party, which has previously reached or hereafter reaches a settlement with Exxon, brings an action against the Governments, or either of them, the sued Government(s) shall undertake to apportion liability, if any, according to principles of comparative fault without the joinder of Exxon, and shall assert that joinder of Exxon is unnecessary to obtain the benefits of allocation of fault. Notwithstanding any other provision of this Agreement, if the court rejects the sued Government(s)' efforts to obtain a proportional allocation of fault without Exxon's joinder, the sued Government(s) may institute third-party actions against Exxon solely for the purpose of obtaining allocation of fault. The Governments in such third-party actions shall not enforce any judgment against Exxon.

Interest for Late Payments

31. If any payment required by Paragraphs 8 or 9 of this Agreement is not made by the date specified in those Paragraphs, Exxon shall be liable to the Governments for interest on the overdue amount(s), from the time payment was due until full payment is made, at the rate established by the Department of the Treasury under 31 U.S.C. § 3717(a)(1) & (2). Interest on an

overdue payment shall be paid in the same manner as the payment on which it accrued.

Reservations of Rights

32. This Agreement does not constitute an admission of fact or law, or of any liability, by any Party to this Agreement. Except as expressly stated in this Agreement, each Party reserves against all persons or entities all rights, claims, or defenses available to it relating to or arising from the Oil Spill. Nothing in this Agreement, however, is intended to affect legally the claims, if any, of any person or entity not a Party to this Agreement.

33. Nothing in this Agreement creates, nor shall it be construed as creating, any claim in favor of any person not a Party to this Agreement.

34. Nothing in this Agreement shall prevent or impair the Governments from providing program assistance or funding to those not signatories to this Agreement under the programs of their agencies pursuant to legislative authorization or appropriation.

35. Nothing in this Agreement shall affect or impair any existing contract between Exxon or Exxon Pipeline and any entity of either Government, including without limitation the agreement between Exxon and the Environmental Protection Agency dated December 21, 1990, relating to joint conduct of bioremediation studies.

Notices and Submittals

36. Whenever, under the terms of this Consent Decree, written notice is required to be given by one Party to another, it shall be directed to the individuals and addresses specified below, unless those individuals or their successors give notice of changes to the other Parties in writing.

As to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
10th and Pennsylvania Avenue, N.W.
Washington, D.C. 20530
Attn. DOJ #90-5-1-1-3343

Chief, Admiralty and Aviation Branch
Civil Division
U.S. Department of Justice
601 D Street, N.W.
Washington, D.C. 20530

General Counsel
National Oceanic and Atmospheric Administration
Department of Commerce
14th & Constitution Avenue, N.W.
Washington, D.C. 20230

As to the State of Alaska:

Attorney General
State of Alaska
Pouch K
Juneau, Alaska 99811

Supervising Attorney
Oil Spill Litigation Section
Department of Law
1031 W. Fourth Street, Suite 200
Anchorage, Alaska 99501

As to Exxon Corporation:

Office of the Secretary
Exxon Corporation
225 E. John W. Carpenter Fwy.
Irving, Texas 75062-2298

ACE 7228217

General Counsel
Exxon Corporation
225 E. John W. Carpenter Fwy.
Irving, Texas 75062-2298

As to Exxon Shipping Company:

Office of the President
Exxon Shipping Company
P.O. Box 1512
Houston, Texas 77251-1512

As to Exxon Pipeline:

Office of the President
Exxon Pipeline Company
P.O. Box 2220
Houston, Texas 77252-2220

Election to Terminate

37. Any Party may elect to terminate this Agreement if:

(1) any court of competent jurisdiction disapproves or overturns any plea agreement entered into between the United States and Exxon in United States v. Exxon Shipping Co., No. A90-015 CR (D. Alaska); (2) a final judicial determination is made by such court that this Agreement will not be approved and entered without modification; or (3) such court modifies this Agreement in a manner materially adverse to that Party, or interprets a material provision of this Agreement in a manner inconsistent with the Parties' intentions, prior to or contemporaneously with a final judicial determination approving the Agreement as modified. A Party electing to terminate this Agreement pursuant to this paragraph must do so within 10 days after an event specified in the preceding sentence, and shall immediately notify the other Parties of such election in writing by hand delivery, facsimile,

ACE 7228218

or overnight mail. Termination of this Agreement by one Party shall effect termination as to all Parties. For purposes of this paragraph, "termination" and "terminate" shall mean the cessation, as of the date of notice of such termination, of any and all rights, obligations, releases, covenants, and indemnities under this Agreement, provided, that termination shall not affect or impair Exxon's rights to obtain return of any deposits made into the Escrow pursuant to the final sentence of Paragraph 9, and provided further, that the provisions of Paragraphs 11 and 12, relating to clean-up, shall continue in effect notwithstanding any termination.

Retention of Jurisdiction

38. The Court shall retain jurisdiction of this matter for the purpose of entering such further orders, direction, or relief as may be appropriate for the construction, implementation, or enforcement of this Agreement.

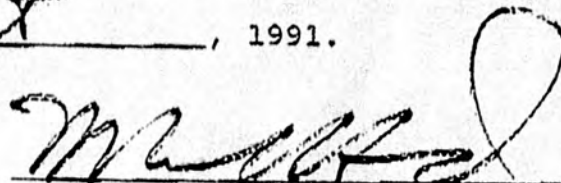
Miscellaneous

39. This Agreement can be modified only with the express written consent of the Parties to the Agreement and the approval of the Court.

40. Each undersigned representative of a Party to this Agreement certifies that he or she is fully authorized to enter into the terms and conditions of this Agreement and to execute and legally bind such Party to this Agreement.

- 30 -

THE FOREGOING Agreement and Consent Decree among plaintiffs the United States of America and the State of Alaska and defendants Exxon Corporation, Exxon Shipping Company, Exxon Pipeline Company, and the T/V EXXON VALDEZ, is hereby APPROVED AND ENTERED THIS 8 DAY OF Oct, 1991.



Honorable H. Russel Holland
United States District Judge
District of Alaska

cc: B. Herman (AAG-200)
W. Bankston (BANKSTON)
D. Serdahely (BOGLE)
J. Clough, III

ACE 7228220

[Agreement and Consent Decree in United States v. Exxon Corporation, et al. (D. Alaska)]

FOR THE UNITED STATES OF AMERICA

Date: Sept 25, 1991

Barry M. Hartman
BARRY M. HARTMAN
Acting Assistant Attorney General
Environment and Natural Resources
Division
U.S. Department of Justice
Washington, D.C. 20530

Date: Sept. 24, 1991

Stuart M. Gerson
STUART M. GERSON
Assistant Attorney General
Civil Division
U.S. Department of Justice
Washington, D.C. 20530

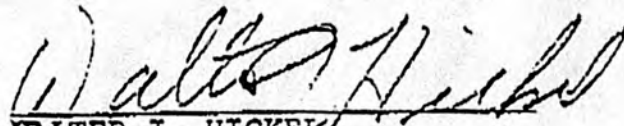
FOR THE STATE OF ALASKA

Date: Sept 25, 1991

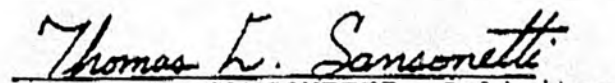
Charles E. Cole
CHARLES E. COLE
Attorney General and Lead State
Trustee
State of Alaska
Pouch K
Juneau, Alaska 99811

[Agreement and Consent Decree in United States v. Exxon Corporation, et al. (D. Alaska)]

Date: _____


WALTER J. HICKEY
Governor
State of Alaska

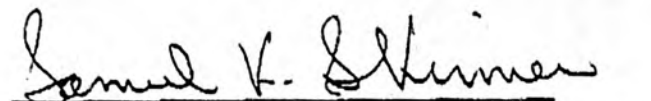
Date: _____


THOMAS L. SANSONETTI, Solicitor
U.S. Department of the Interior

Date: _____


ALAN CHARLES RAUL, General Counsel
U.S. Department of Agriculture

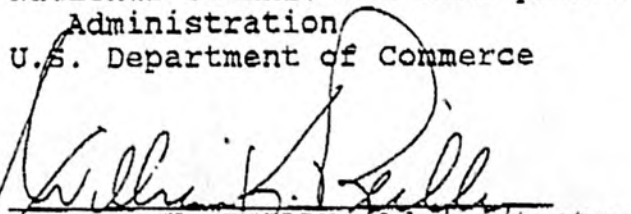
Date: _____


SAMUEL K. SKINNER, Secretary
U.S. Department of Transportation

Date: _____


THOMAS A. CAMPBELL, General Counsel
National Oceanic and Atmospheric
Administration
U.S. Department of Commerce

Date: _____


WILLIAM K. REILLY, Administrator
U.S. Environmental Protection
Agency

[Agreement and Consent Decree in United States v. Exxon Corporation, et al. (D. Alaska)]

FOR EXXON CORPORATION

Dated: Sept 25, 1991

Edward J. Lynch
EDWARD J. LYNCH
Associate General Counsel
Exxon Corporation
225 E. John W. Carpenter Freeway
Irving, Texas 75062-2298

Dated: Sept. 25, 1991

Patrick Lynch
PATRICK LYNCH
O'Melveny & Myers
400 South Hope Street
Los Angeles, CA 90071

Dated: _____

John F. Clough III
JOHN F. CLOUGH III
Clough & Associates
431 North Franklin Street, Suite 202
Juneau, Alaska 99801

FOR EXXON SHIPPING COMPANY and T/V EXXON VALDEZ

Dated: 9/25/91

James F. Neal
JAMES F. NEAL
Neal & Harwell
2000 One Nashville Place
150 Fourth Avenue North
Nashville, Tennessee 37219

Dated: _____

Robert C. Boney
ROBERT C. BONEY
Bogle & Gates
1031 West 4th Avenue, Suite 600
Anchorage, Alaska 99501

FOR EXXON PIPELINE COMPANY

Dated: 9-25-91

John R. Reeman
JOHN R. REEMAN
Attorney for Exxon Pipeline Company
P.O. Box 2180
Houston, Texas 77252-2180

Dated: _____

Randall J. Weddle
RANDALL J. WEDDLE
Faulkner, Banfield, Doogan & Holmes
550 West 7th Avenue, Suite 1000
Anchorage, Alaska 99501

FILED

OCT 09 1991

UNITED STATES DISTRICT COURT
DISTRICT OF ALASKA
[Signature]

UNITED STATES DISTRICT COURT
DISTRICT OF ALASKA

STATE OF ALASKA,

Plaintiff,

v.

EXXON CORPORATION, et al.,

Defendants,

No. A91-083 Civil

JUDGMENT

Judgment is hereby rendered in this action on the terms and conditions set forth in the Agreement and Consent Decree entered as an order of the Court on the 8 day of Oct, 1991.

ENTERED this 8 day of Oct, 1991.

[Signature]
United States District Judge

cc: O & J 4464
B. Herman (AAG-200)
W. Bankston (BANKSTON)
D. Serdahely (BOGLE)
J. Clough, III

ACE
COPY

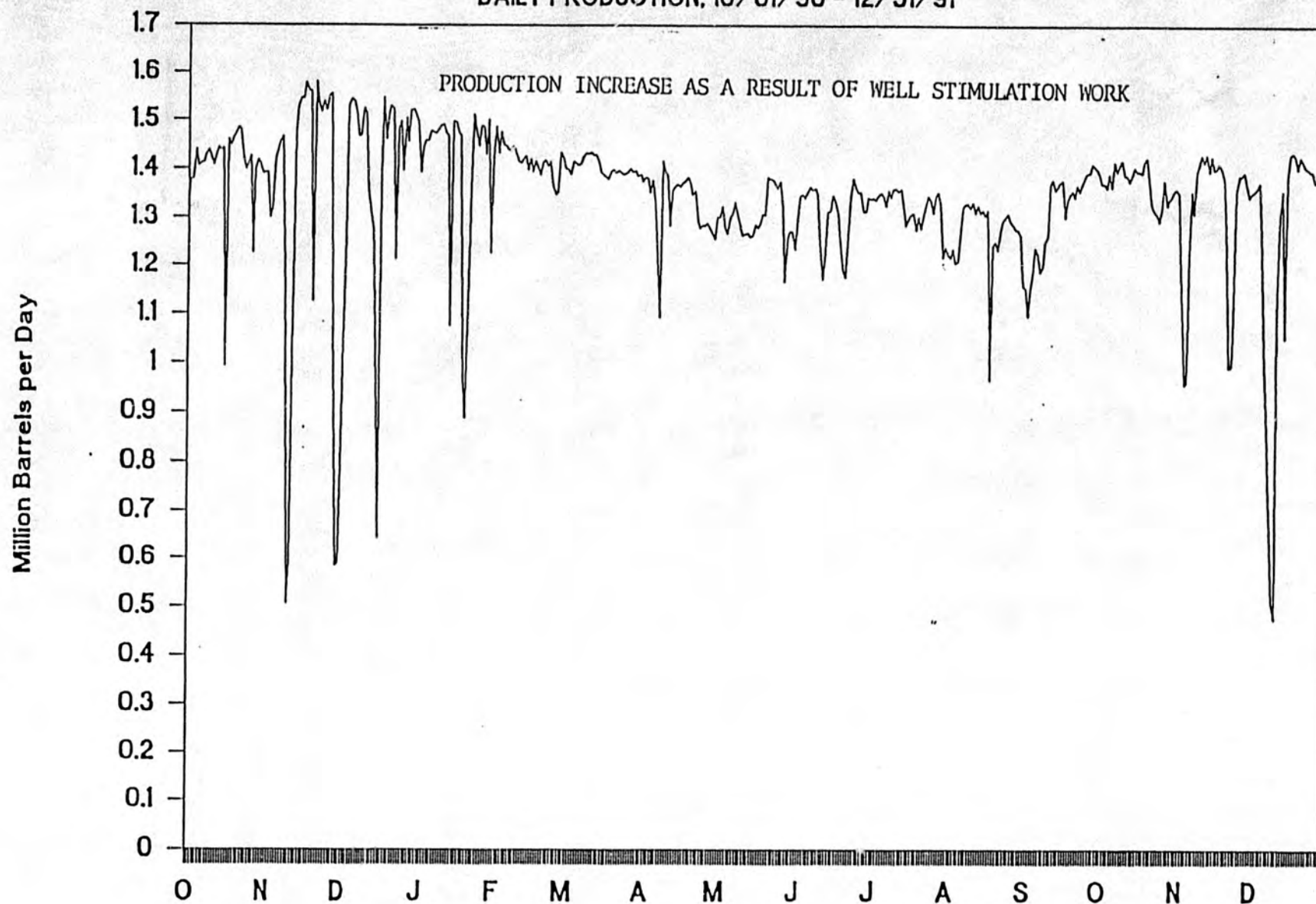
ACE 7228190

SCOMM

79:7

PRUDHOE BAY

DAILY PRODUCTION, 10/01/90 - 12/31/91



DIVISION OF OIL AND GAS
JANUARY 17, 1992

1/17/92

Prudhoe Bay Chronology

Date Specific Projects

- 1977--start up of production; implementation of a water flood assumed
- 1982--start up of Flow Station 3 enhanced oil recovery pilot project
- 1984--start up of full field water flood project
- 1986--start up of Central Gas Facility
- 1987--start up of large scale Prudhoe Bay Miscible Gas Project (PBMGP) EOR project
- 1988--start up of the West End/Eileen drillsites
- 1990--start up of GHX-1 project
- 1991--start up of the Hurl State/P Pad drillsite
- 1995--proposed start up of GHX-2 project and apex gas injection

Ongoing Projects

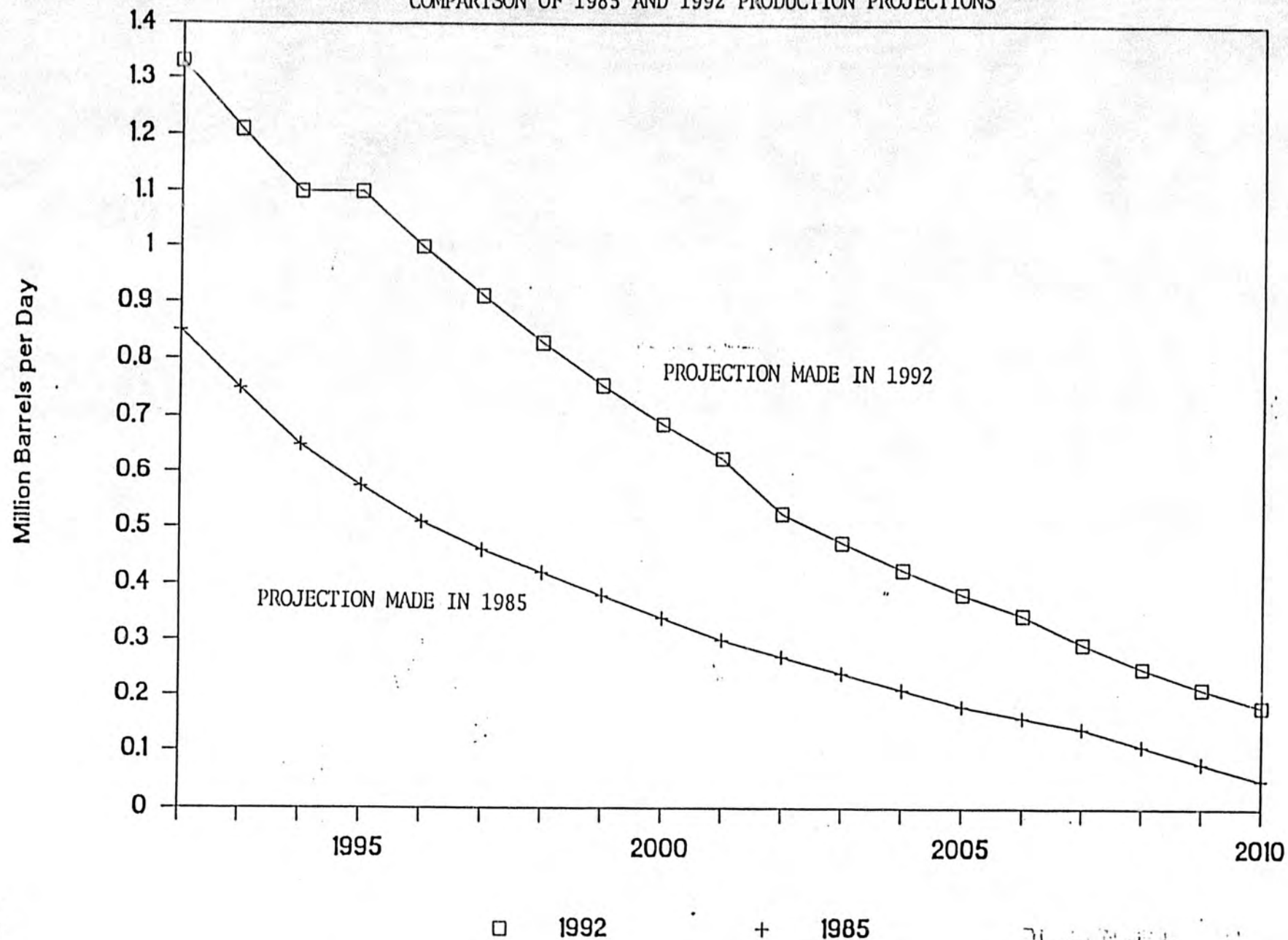
The following projects are not date specific:

1. infill drilling--well spacing has been reduced from the initial 320 acres per well to 160 or 80 acres per well depending on location in the field. Pilot projects are underway to evaluate the success of 40 acre well spacing. The ultimate well count in the field will likely double the original estimate.
2. peripheral drilling--wells are being drilled out to the edge of the oil accumulation to recover previously untapped oil reserves. During the early production years wells were not drilled in areas with less than 100 feet of oil pay.
3. gas cycling--although both the GHX 1 and 2 projects are major expansions of the gas cycling project, gas cycling has been occurring since field start up.
4. expansions in water handling facilities--as with gas handling facilities, if the produced water can not be processed due to a constraint in water processing capacity then oil/water production must be curtailed to avoid facilities overload.

Division of Oil and Gas
January 17, 1992

PRUDHOE BAY

COMPARISON OF 1985 AND 1992 PRODUCTION PROJECTIONS



DIVISION OF OIL AND GAS
JANUARY 17, 1992

(W)

Remaining Prudhoe Bay Oil Recovery
By Time Period

Time Period (years)	Oil Recovery (bbls)
1992-2000	3.26 billion
2001-2005	0.89
2006-2010	0.47
2011-2016	<u>0.23</u>
Total	4.85 billion

Remaining recovery after the year 2000-- 1.59 billion barrels

Remaining recovery after the year 2005-- 0.70 billion barrels

notes: Remaining oil recovery and timing estimates taken from
Division of Oil and Gas PBU production forecast.

Oil production for the period beyond the year 2010 assumes
that TAPS is still operational.

Division of Oil and Gas
January 17, 1992

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

January 17, 1992

WALTER J. HICKEL, GOVERNOR

3001 PORCUPINE DRIVE
ANCHORAGE, ALASKA 99501-3192
PHONE: (907) 278-1433
TELECOPY: (907) 276-7542

The Honorable Mike Navarre
The Honorable Bill Hudson
Alaska State Representatives
P. O. Box V
Juneau, Alaska 99811

Dear Representatives Navarre and Hudson:

The Alaska Oil and Gas Conservation Commission welcomes the opportunity to appear before the joint session of the House Finance Committee and the House Oil and Gas Committee to discuss your concerns with Prudhoe Bay production management. Recently the commission concluded hearings on the expansion of the Prudhoe Bay Miscible Gas Project. Testimony offered by the unit operators included a full review and update of the past and current reservoir management plan for Prudhoe Bay. The commission has not yet issued an order in this matter.

While the commission could have approved the expansion of the Miscible Gas Project by administrative action without public hearing, we chose a process more open to public involvement out of respect for every Alaskan's right to be informed about the management of a resource that is vital to their interests. Our intent was to inform, not to confuse or to create controversy over gas sales or with Prudhoe Bay reservoir management. The hearings were not held to discuss gas sales nor to revisit the entire scope of management options for the Prudhoe oil reservoir. The commission will, however, hold such public hearings when gas sales are actually proposed or become more likely.

Turning our attention to the specific question you asked in your January 14 letter, we will address each in turn.

1. What effort has the AOGCC made to ensure that all feasible enhanced recovery techniques and other options

#1

(such as in-fill drilling) have been or will be undertaken by the producers?

Generally recognized enhanced recovery processes include: a) miscible gas displacement, b) surfactant flooding, c) enhanced waterflood techniques and d) thermal processes. The commission has reviewed each process for application in the Prudhoe Bay reservoir. Of these processes, miscible gas displacement is judged to be the most effective for Prudhoe Bay. Enhanced oil recovery processes are described in greater detail in Attachment A.

Other methods for improving oil recovery at Prudhoe Bay include infill drilling, high angle and horizontal drilling, well workovers, stimulations, fracture stimulations, water and gas influx control, redrills and coiled tubing work. These methods have been employed since initial production, and are generally recognized as contributing significantly to the sustained production rate from the reservoir. Development work during the next five years calls for 50 fracture treatments per year, 200 non-frac acid/chemical treatments per year, 200 nonrig workovers per year to control gas/water influx and profile modifications, 85 workovers per year to repair wells and 35 redrills per year, all providing a yearly rate benefit of 85 MBOPD.

Commission reservoir surveillance efforts insure that these processes will continue, and are applied as appropriate across the entire field. The commission works closely with the operators to insure that these operations are conducted expeditiously and in accordance with state regulations. Our permit turn around time is quite rapid relative to other agencies, and our petroleum field inspection program provides comprehensive follow up review of drilling and workover operations. We also interface with other agencies to ensure continued smooth operation of the field. As an example, our work with EPA has allowed rapid resolution of disposal problems with exploration and production wastes, including NORM waste and reserve pit close out.

It is important for the committee members to understand that good reservoir management is an evolutionary process. As knowledge is gained about the geology and productive mechanisms at work in the reservoir, development plans will

continue to evolve and improve. For example, initial plans for Prudhoe Bay called for 1.5 million barrels per day offtake, 2 Bcf per day gas handling capacity, nominal 160 acre well spacing, gas lift system, waterflooding, and gas sales five years after start up, with initial recoverable reserves estimated to be 9.6 billion barrels. Current plans call for full field 80 acre well spacing with some 40 acre development, gas handling capacity to 7.5 Bcf per day, miscible gas EOR, and NGL production, resulting in estimated total recoverable reserves of 12 billion barrels. Commission oversight will help ensure that this evolutionary process continues throughout the productive life of the reservoir.

2. What is the AOGCC's understanding of the relationship between potential gas sales, reservoir performance and total hydrocarbon recovery?

The relationship between gas sales, reservoir performance and total hydrocarbon recovery is dependent on a number of variables, primary among these are the timing of sales and proposed gas offtake rate. Basic economics, including the price of oil, price of gas, capital investment costs, available markets, taxes, tariffs, and the effect of government regulations also have direct bearing on the optimum depletion plan.

As we indicated in our letter to Representative Brown, formal effort to quantify the relationship between gas sales and hydrocarbon recovery is limited to the commission's reservoir modelling work done in the late 70's and early 80's. Our awareness of Prudhoe Bay reservoir dynamics today comes from monitoring oil production and field operations for over 14 years and from numerous discussions, both formal and informal, held with the producers during each year of that period.

Our information from these discussions tells us that gas sales are unlikely until sometime after the year 2005. Based upon this assumption, the commission has little concern that optimum recovery of both oil and gas would be obtained. If, on the other hand, gas sales occurred before that date, our attention would focus on the more rapid depletion of reservoir pressure and the possibility of

reduced oil recovery. Estimates have been made that with sales of one Bcf per day, the pressure in the Prudhoe Bay reservoir would decline about 50 psi per year, at two Bcf per day, it declines about 70 psi per year. Assuming these estimates are accurate, the commission would not be overly alarmed by this decline. Although it is more rapid than the current anticipated rate of 30 psi per year, we do not believe it would have a drastic affect on total oil recovery. Several factors mitigate our concern. First, gas sales will likely prolong the economic life of the field, allowing more oil to be produced over time. Secondly, while less gas would be available for cycling, the total pore volume of gas cycled over time may actually increase with longer field life. Thirdly, gas sales may actually increase the availability of enriching components for building the miscible injectant, allowing continued, or possibly expanded, use of the miscible gas displacement process. Finally, with gas sales of two Bcf per day, a 35 to 40 year supply of gas is available in Prudhoe Bay. Associated infrastructure would likely contribute to the continued and expanded development of other North Slope oil and gas fields.

The commission cautions, however, that further study should be undertaken to better confirm the relationship between gas sales and oil recovery when a definitive proposal is offered or appears more likely.

3. Given the AOGCC's statutory charge to prevent the waste of oil and gas resources, what specific, independent analysis has the commission performed concerning additional or alternative enhanced recovery projects? If an analysis was performed, what was the source of the base-data; how was it manipulated?

The commission's most extensive independent analysis was its three dimensional simulation study done in the late 70's and early 80's. This is the VanPoolen study referred to in Representative Brown's letter. The study exceeded three million dollars, but provided the framework for much of the development rules that govern Prudhoe Bay today. At the time, it was a precedent setting study for a conservation commission. Even today, we are not aware of any other studies by conservation commissions that compare to the

VanPoolen study, with the possible exception of some Canadian studies and an offshore California study.

Since then, our efforts have been focused on inhouse review of the operator's proposals using existing staff. The commission monitors production data, pressure data, and injection data, and uses this data to determine the effectiveness of voidage replacement. We monitor production decline, gas-oil and water-oil ratios, gas-oil contact movement, and cumulative production. We meet annually with the operators to review reservoir management plans and results of field performance monitoring studies required by the commission. We continually review field operations, including well workovers, stimulations, fracture treatments, and development drilling to ensure optimal reservoir development. We work informally with the operator to encourage expanded development, and have influenced increased gas handling capacity, apex gas injection, infill drilling, use of high angle and horizontal wellbores, and development of the West Eileen area.

Concerning the commission's work on enhanced recovery projects, our initial efforts using the 3-D study showed that waterflood would increase ultimate recovery. Based on this assessment, the commission encouraged the operators to begin waterflood early in the productive life of the field. Waterflood pilots began in 1979, with full scale waterflood implemented in 1984. By this time the operators had already applied for and received approval from the commission for a pilot miscible gas project in the Flow Station 3 area. Excellent results of this pilot project, and concurrent lab study and modeling, prompted the operators to apply for expansion of the miscible gas project to other areas of the field. The Prudhoe Bay MGP was approved by the commission in 1984, with start up in 1987 following installation of the Central Gas Facility. The MGP applications were reviewed by commission staff and its consultant, H. K. vanPoolen and Associates, Inc.. Our assessment considered the viability of other EOR options as described under question 1. We determined that the MGP was the best option for Prudhoe Bay EOR. Current estimates are that approximately 500 million barrels of additional oil will be recovered by miscible gas injection.

Today, we are again considering an expansion of the MGP. The commission considers this latest request to be the fifth increment of the project. The commission remains convinced that this EOR option remains the best alternative for Prudhoe Bay.

4. (paraphrasing) The question in your reply to Representative Brown, "How does one ensure that recovery of the overall resource is optimized, and a line is not drawn improperly between the recovery of gas vis-a-vis oil?" is the salient issue. The very purpose of the commission is to optimize and draw lines regarding hydrocarbon recovery, is it that the commission lacks authority, or has too broad a mandate or has insufficient resources/data to make such decisions? At some point in time these critical issues will have to be addressed. What is the commission doing to prepare for this eventuality?

The question proposed by the commission in its reply to Representative Brown was merely hypothetical. Its purpose is to illustrate the type of information or assurance that must be presented to the commission in its consideration of gas sales. The issue of gas sales, however, does not appear imminent to the commission, but seems to be far enough into the future to allow reasoned and deliberative consideration of the question when the specifics of a gas sale proposal are known. The answer to this question today using only speculative data would likely be different than in the future when an actual proposal is presented.

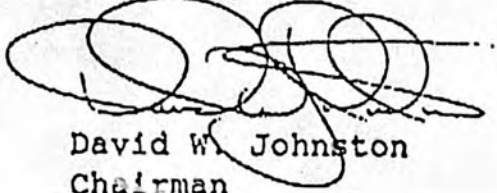
The commission believes it has the proper authority to consider the conservation issues surrounding gas sales, and are prepared to examine these issues when the time is appropriate. Further, we feel that we are the appropriate agency to make a determination in the matter of gas sales.

To prepare for this eventuality, the commission continues improving reservoir description and surveillance capabilities, field inspections, data storage and retrieval, communication and working relations with other state and federal agencies, and are rendering decisions in a more open forum. The commission maintains an effective working relationship with the operators, which is underpinned by our mutual desire to optimize recovery of oil and gas resources.

The commission is a small agency with limited resources. To continue improving in our conservation role we ask for your continued attention and support. As the commission identifies resource requirements, it will continue to request appropriate funding to meet those needs. Our desire is to more clearly define those state needs in forums such as the hearings now being held before the House Finance and Oil and Gas committees.

I hope our response to your questions has helped in your understanding of the issues involved. We will be pleased to answer any additional question you may have.

Sincerely,



David W. Johnston
Chairman

Attachment

cc. House Finance Committee members
House Oil and Gas Committee members
Representative Ben Grussendorf, House Speaker
Representative Max Gruenberg, House Majority Leader
Harold Heinze, DNR
Jim Eason, DNR

Attachment A

Enhanced Recovery Processes

Miscible gas displacement--This process includes two categories: lean gas (vaporizing) drive and enriched gas (condensing) drive. Both categories are utilized in Prudhoe Bay; vaporizing drive occurs in the gas cap and condensing drive occurs in the peripheral area of the field (i.e. PBMGP area). Vaporization occurs when lean gas comes in contact with residual hydrocarbons. The vaporized hydrocarbons are then produced with the gas. Condensing drive uses lean gas enriched with intermediate hydrocarbon components (butane, pentane, etc) to mobilize residual oil, which in turn is pushed toward the producing well by subsequent water injection.

Enhanced Waterflood (or mobility control process)--This process attempts to improve the sweep efficiency of conventional waterflood by various mobility enhancing additives. Three techniques were reviewed for Prudhoe Bay: carbonate waterflooding (CO₂), polymer waterflooding, and caustic waterflooding. However, since a favorable mobility ratio already exists between water and Sadlerochit crude, the use of mobility enhancing techniques would yield limited benefits. Each technique was determined to be less efficient than miscible gas displacement.

Surfactant flooding--This process uses a surfactant to reduce the oil-water interfacial tension, allowing more oil to be mobilized by subsequent waterflooding. Surfactant systems currently available are not effective over a large range of salinity or temperatures, thereby limiting application of this process in Prudhoe Bay which is flooded, in part, with low temperature Beaufort Sea water. Further, the manufacturing and delivery costs make this process uneconomical for Prudhoe Bay.

Thermal Processes--These processes improves recovery by reducing the oil viscosity and by expansion and distillation of the crude. The efficiency of thermal processes below 3000 feet is poor. The technology to use thermal recovery techniques in a reservoir as deep and as large as Prudhoe Bay is not available today.



Alaska State Legislature

HOUSE OF REPRESENTATIVES

Official Business

P.O. Box V
State Capitol
Juneau, Alaska 99811

January 14, 1992

David W. Johnston, Chairman
Alaska Oil & Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK. 99501

Dear Mr. Johnston,

The purpose of this letter is to confirm that the **House Finance Committee**, jointly with the **House Oil and Gas Committee**, will be holding an oversight hearing concerning Prudhoe Bay production management and forecasting issues on January 21, at 1:30 p.m. in Juneau and to ask for the Alaska Oil & Gas Conservation Commission's (AOGCC) assistance in obtaining a better understanding of the issues surrounding long-term projections of total hydrocarbon recovery from the Prudhoe Bay reservoir.

As you are well aware, recent proceedings before the Commission regarding the Prudhoe Bay Miscible Gas Expansion Project involve fundamental issues of long-term, total recovery of oil from the Prudhoe Bay reservoir. In recent correspondence with the AOGCC, a number of questions have been raised concerning the uncertain, although potentially adverse, impact that large scale gas sales could have on ultimate hydrocarbon recovery from Prudhoe Bay.

As you have stated (letter attached), large volume gas sales could impact the reservoir in three ways: field pressure would decline more rapidly, less gas would be available for cycling and the availability of miscible injectant could be affected. At this point, it appears that the state has only a limited understanding of the impact that large volume gas sales would have on the long-term, ultimate hydrocarbon recovery from Prudhoe Bay: "[f]ormal study of the relationship between potential gas sales and reservoir performance is limited to the simulations done with VanPoolen and Associates." As you appreciate, the VanPoolen modelling work is now largely outdated. As indicated by the Commission, the relationship between gas sales and oil recovery is complex and in need of further study.

#2

The uncertain impact gas sales could have on ultimate hydrocarbon recovery — and by implication the state's fiscal interests — is of significant concern. We would appreciate your help in obtaining a clearer understanding of the Commission's view of these concerns.

With specific regard to the hearing on January 21st, it would be very helpful if the Commission would be prepared to comment on the following issues:

1. What effort has the AOGCC made to ensure that all feasible enhanced recovery techniques and other options (such as in-fill drilling) have been or will be undertaken by the producers?
2. What is the AOGCC's understanding of the relationship between potential gas sales, reservoir performance and total hydrocarbon recovery?
3. Given the AOGCC's statutory charge to prevent the waste of oil and gas resources, what specific, independent, analysis has the Commission performed concerning additional or alternative enhanced recovery projects? If an analysis was performed, what was the source of the base-data; how was it manipulated?
4. In your letter to Representative Brown, you closed by raising the most salient issues. "How does one", you asked, "ensure that recovery of the overall resource is optimized, and a line is not improperly drawn between the recovery of gas vis-a-vis oil?" To optimize and draw lines, regarding hydrocarbon recovery, appears to be the very purpose for which the Commission was established and entrusted with broad regulatory powers. Is it that the Commission views these powers as inadequate, their mandate as overly broad, or is it a matter of insufficient resources/data to make such decisions? At some point in time these critical issues will have to be addressed (and not just for Prudhoe Bay). What is the Commission doing to prepare for this eventuality?

Your response to these questions would be greatly appreciated. We look forward to a discussion of these issues on January 21.

Sincerely,



Representative Mike Navarre
Co-Chair, House Finance Committee



Representative Bill Hudson
Chair, House Oil & Gas Committee

cc: House Finance Committee members
House Oil & Gas Committee members
Jim Eason/Division of Oil and Gas
Bill Van Dyke/Division of Oil and Gas
Dave Johnston/Alaska Oil & Gas Conservation Commission
Representative Ben Grussendorf, House Speaker
Representative Max Gruenberg, House Majority Leader

STATE OF ALASKA

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

WALTER J. HICKEL, GOVERNOR

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

December 17, 1991

David W. Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501

RE: Petition to Amend Conservation Order Number 195 Rule 2 and Request for Approval of Significant Expansion of the PBUMGP

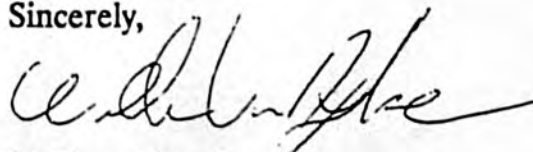
Dear Mr. Johnston:

The Alaska Oil and Gas Conservation Commission held a hearing on November 18, 19 and 20, 1991 in connection with the above referenced topics. The hearing was continued to December 20, 1991. In response to that hearing the Department submits the enclosed comments and suggested questions for the applicants. A brief statement of the overall rationale for some of the questions is also included. In this submittal we have not repeated any questions that were answered at the earlier proceedings. We have ask again the questions that we believe were not fully answered at the earlier sessions.

It is our understanding that the hearing will be reconvened at 9:00 am on Friday December 20, 1991 at the Commission's office. The Department will have a representative at the hearing to make an opening statement and to answer any questions the Commission may have at that time.

If you have any questions in the interim please contact me at the above address or phone me at 762-2550.

Sincerely,



William Van Dyke
Petroleum Manager

Overall Rational for Questions Asked by the Department of Natural Resources
December 17, 1991

The petition at hand requests the Commission's approval of an amendment to Conservation Order 195 Rule 2 and the Commission's concurrence that the expansion of the PBUMGP is a bona fide EOR project. New MI patterns will be added, infill MI patterns will be added, apex gas injection will be commenced and gas cycling volumes will be increased significantly. Taken in total, these projects represent a major change in reservoir management plans and strategies relative to those approved by the Commission in the mid 1980s.

Even without the implementation of these new projects and strategies, reservoir management strategies and facilities have evolved since the early field rules hearings. Water handling and gas handling facilities have been expanded, infill drilling is more prevalent, the GHX-1 project has resulted in increased gas cycling capability, condensate production and MI availability, and well stimulation and workover techniques have greatly improved. The waterflood, EOR project and the gas cycling strategy are all performing as good as or better than predicted and today's estimate of ultimate recovery is considerably above the original 9.6 billion barrels of oil. The operators have done an excellent job at implementing the plans and adapting to change and better information. No doubt the plans being proposed today will change to some degree in the future as new information becomes available. No one should expect that the plans presented in connection with this hearing are or should be the final word in reservoir management strategy. However, the factors and constraints that lead to the choices that were adopted should be understood before those choices are adopted or endorsed by the Commission.

It seems only appropriate that the Commission would want to review the reservoir management options that are available to the operators, study the alternatives that have been investigated to date and understand the degree of sensitivity that the major production and operation decisions have on ultimate recovery and timing of production. This hearing provides the ideal venue to investigate these issues and build a proper record to support the requests made by the applicants. The requests need to be considered in light of the potential effects and impacts on the entire reservoir. Although three distinct recovery mechanisms are operating--gravity drainage, waterflood/WAG MI and gas cap cycling--the field geology is such that fluid flow and pressure transients can not be constrained within exact areas. The record should be complete as to options studied, likely production cases investigated and sensitivities described.

There is no need to rush the decision making process. If necessary the Commission can

Page 2

December 17, 1991

Overall Rational

approve a reduction in the PBU reservoir pressure to 3500 psia and even order the implementation of the apex gas injection project while the long term plans are being carefully studied. Once the record with respect to production forecasts, WAG ratio schedules, MI composition schedules, gas utilization options, options for alternative EOR methods and the like is more complete the Commission can issue final rulings on the requests at hand. The Commission most likely will not have the manpower and fiscal resources available to it to independently track and evaluate the behavior of the Prudhoe Bay reservoir in future years. Having the operators present a complete status report and projection every five or so years has great merit and provides the Commission and other effected parties with an opportunity to evaluate the then in place production strategy. Long term relief and abandonment of Commission oversight of reservoir management practices should only be approved after full consideration by the Commission and only after a complete record is established.

The Department believes that the data have been collected and studies completed to show that all the likely production/operation options have been considered and that the proposal at hand is the "best" one available. The applicants and other owners at Prudhoe Bay should share this information with the Commission and include it in the hearing record. As an alternative the Commission could take pause in this hearing process to replicate the work that has been done by the owners. This option would no doubt take four or five years to complete given the appropriation and contracting constraints facing the Commission. A third option would be to have all the data reviewed by a third party and then have the third party present the results of that review to the Commission and include it in the record. Funding for the third party peer review could be negotiated between the Commission and the applicants. The applicants have described in qualitative terms what they propose to do. Before the Commission rules on the petition it should request a quantitative analysis of the proposed reservoir management strategy.

Conservation Orders apply to the specific field in question. The current operators at Prudhoe Bay have shown their ability to properly manage the field. However, there is no guarantee that the current operators will remain in place for the next 30 years. The Commission's approval criteria should include this possibility.

New Questions Submitted by the Department of Natural Resources
December 17, 1991

Listed below are new questions that were not part of the Department of Natural Resources submittal dated November 18, 1991.

1. What other methods of EOR have been investigated for the Sadlerochit reservoir? SPE papers 20220 and 20236 (Title pages attached) discuss the application of a polymer/surfactant EOR method. Has this process been investigated for Prudhoe Bay? Is it viable?
2. Has the use of a tapered MI slug been investigated? Will any tapered slugs be used at Prudhoe Bay?
3. SPE paper 24159 describes a new MI allocation method currently being used in the field. Will the overall life of the current EOR project or the overall ultimate recovery change as a result of using the new MI allocation method? Will this method also be used in the expansion and infill areas? What range of WAG ratios will result from the new method? Will the field rules be amended to reflect this change in operating strategy?
4. Exhibit B-61 shows an estimated production rate for the year 2000 and the year 2010 by recovery method. Is there a similar forecast for the year 2020? What happens after the year 2010? Between the year 1990 and the year 2000 production declines by over 60%. What is the cause of this rapid drop in oil production rate? Why is the rate of decline slower after the year 2000? Would a different reservoir management strategy lessen the decline rate during the next 10 years?
5. What are the benefits of accelerating the start up of apex gas injection?
6. What are the consequences of designing the MI slug with a 500 psi "safety factor" verses the proposed 250 psi differential? Would this be a cheap form of insurance against faster than expected pressure drops or unpredicted compositional changes? If a richer slug is needed to accommodate a larger pressure buffer, what decrease in volume of available MI would accompany this richer MI slug requirement?
7. If the MI slug loses miscibility while in the reservoir does the oil bank established up to that point still get displaced to a production well?
8. Do the existing production wells in the PBUMGP area have an MI cone around them from the coning down of MI in to the wells?
9. Exhibit B-38 indicates that the equation of state predicts the lean gas crude oil vaporization process quite well. Is there lab data available that shows how well the equation predicts miscibility? Have one or two or three dimensional laboratory model MI floods been compared to numerical models of the same?

SPE/DOE 20220

The Low-Tension Polymer Flood Approach to Cost-Effective Chemical EOR

B. Kalpakci* and T.G. Arf, BP Research; J.W. Barker,* BP Research Sunbury; A.S. Krupa, BP Research; J.C. Morgan,* BP Research Sunbury; and R.D. Neira, BP Research

*SPE Members

Copyright 1990, Society of Petroleum Engineers Inc.

This paper was prepared for presentation at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery held in Tulsa, Oklahoma, April 22-25, 1990.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Write Publications Manager, SPE, P.O. Box 833836, Richardson, TX 75083-3836. Telex, 730989 SPEDAL.

ABSTRACT

The Low Tension Polymer Flood approach addresses the two EOR problems of cost and control. Coinjection of low concentration surfactant and a biopolymer, followed by a further mobility control buffer, leads to much reduced overall chemical consumption, even in relatively high clay content rock. Though the optimum chemical injection period is more prolonged, the oil recovery timescale is not unduly prolonged. The LTPF process moves chemical flooding surfactant a long way toward being a simple, low-level waterflood additive process, attractive for field operations. It uses surfactant-polymer interactions as an advantage rather than coping with them as a problem.

The chemical system described is based on a scleroglucan biopolymer (500 - 750 ppm) plus surfactant mixture (3000 ppm total surfactant). No cosolvent is used. This system was developed specifically for use with high salinity injection water (seawater) in a high temperature reservoir. The essential phase behavior description is given, together with other physical parameters and detailed coreflood performance.

Finally, we discuss the computer simulation approach used to predict reservoir performance and the results obtained.

INTRODUCTION

Many surfactant-polymer field tests have been conducted over the past three decades. This activity stemmed from the promise of highly effective oil recovery by surfactants in a period of increasing oil prices. Results of these tests and critical reviews published on them identified the main parameters important to the technical success of a surfactant-polymer project.¹⁻¹⁵ One of the key findings is that preflushes to remove excessive salinity and hardness have been ineffective and chemical systems capable of being effective in the presence of both injection brine and formation water are needed.^{1-2,5-6}

A second important conclusion is that effective and timely oil recovery from surfactant-polymer field tests correlates well with maintaining good mobility control of both the surfactant slug and the polymer buffer^{3,4}. Further, as the pattern size increases so does the need for having a salinity tolerant system with favorable mobility control. However, this is not meant to suggest that other design parameters such as low interfacial tension and high injectivity are unimportant. Rather, we should focus on robustness and control as also being mandatory.

In this context, waterflood modification with viscous polymer alone is usually reported as being technically and economically successful in field operations addressing mobility control problems.^{7,8} However the process effectiveness is generally low. If successful, oil recoveries are in the range of 2-12% of the residual oil⁹.

Since the oil price fall of 1986, concerns over the risks, costs, ineffectiveness and test failures considered to be associated with chemical flooding have led to widespread abandonment of chemical EOR research by the scientific community. In addressing these concerns we decided to explore ways of combining the effectiveness of surfactants with the control of polymers. The properties of the combined system, which we refer to as Low Tension Polymer Flood (LTPF), can confer some significant advantages.

The aim of LTPF is to increase the oil recovery of a relatively ineffective but low chemical cost polymer flood by the addition of limited amounts of polymer compatible surfactants. The basic LTPF injection scheme described here involves the injection of up to 0.7 swept pore volume (PV) of LTPF with additives comprising about 3000 ppm surfactant(s) and 500-750 ppm polymer in a brine. This is followed by 0.5 PV of graded viscosity polymer buffer. However, optimum flood design, including presence or absence of a polymer preflush and length/level of chemical additions, depend on reservoir description. If operationally attainable, the salinity of the make-up water used for the polymer buffer may be made lower than that used during LTPF injection to take advantage of the salinity gradient effect. Thus LTPF is technically a bridge between the surfactant and polymer flooding processes.

References and Illustrations at end of paper.

SPE/DOE 20236

Co-Deployment of Surfactant/Polymer and Miscible Gas Enhanced Oil Recovery Processes: A Simulation Study

J.W. Barker, BP Research Centre

SPE Member

Copyright 1990, Society of Petroleum Engineers Inc.

This paper was prepared for presentation at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery held in Tulsa, Oklahoma, April 22-25, 1990.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Write Publications Manager, SPE, P.O. Box 833836, Richardson, TX 75083-3836. Telex, 730989 SPEDAL.

ABSTRACT

A reservoir simulator capable of modelling both surfactant/polymer flooding and gas displacement processes (immiscible or miscible) is described. Novel extensions to existing phase behaviour and relative permeability models are used to represent interactions between the two processes. Results are presented quantifying the possibilities for combined chemical and miscible EOR.

1. INTRODUCTION

Waterflooding rarely recovers more than half the original oil in place in a reservoir. Miscible gas flooding and surfactant/polymer ("chemical") flooding are two enhanced oil recovery techniques that might be applied to recover a substantial fraction of the waterflood residual oil. Normally, these processes are regarded as alternatives, and one or the other (usually neither) may be selected depending on circumstances such as oil type, permeability, lithology, clay content, and gas availability.

The sweep efficiency of miscible gas floods is frequently limited by gravitational segregation, viscous fingering, and channelling of injected gas towards the production wells. Thus, substantial amounts of oil remain in the reservoir after such a flood, and this oil could still be a target for a chemical flood, which can have a high sweep efficiency. In particular, since the miscible gas will tend to rise to the upper layers of the reservoir, while the water-soluble chemicals will tend to underdrive the oil in most cases, there may be scope for the two processes to act almost independently.

Earlier work¹ has shown the benefits of using polymer in a surfactant flood for mobility control purposes. Recent research² has shown that polymer can interact with the surfactant to produce greater reductions in interfacial tension, and to maintain the activity of the surfactant down to very low concentrations. This observation has led to the development of a Low

Tension Polymer Flood (LTPF) system, which can achieve high oil recovery efficiency at low chemical concentrations, which has low adsorption, and which can tolerate high temperatures, salinities, and a divalent ion concentrations.

Natural targets for the LTPF system are large reservoirs which have been developed by waterflooding. However, some of these reservoirs are already subject to miscible WAG flooding, so it is of interest to know whether the LTPF process could be applied successfully in these cases. To answer this question quantitatively requires examination of both EOR processes within the same simulation model.

In this paper, a reservoir simulator ("BPOPE") capable of modelling both processes is described. Novel extensions to existing phase behaviour and relative permeability models are used to represent the interactions between the two processes. Illustrative calculations are presented which quantify the possible oil recovery from a chemical flood applied in combination with miscible gas injection. Two different reservoir descriptions are used in the calculations. The results indicate that, in some cases, the potential for successful application of chemical flood is not significantly affected by prior miscible gas flood.

2. OVERVIEW OF THE BPOPE SIMULATION MODEL

BPOPE is a multi-phase, multi-component reservoir simulation model. It has been developed in-house at the BP Research Centre, Sunbury, UK, from an earlier version of the University of Texas chemical flood model, UT-CHEM³. Developments introduced at BP include reformulation of the basic equations (following Acsal⁴) to allow for compressibility, modelling temperature variations and their effects on phase behaviour, a model for the surfactant/polymer interaction, a general orthogonal curvilinear coordinate system, generalised boundary conditions, FCT (Flux Corrected Transport) algorithm for control of numerical dispersion, an efficient ICCG (Incomplete Cholesky Conjugate Gradient) solver for the pressure equation, and models for miscible and immiscible

References and figures at end of paper.

December 17, 1991

List of Selected Questions from November 18, 1991 Department of Natural Resources
Submittal with Rational for Continuing with Those Lines of Questions

Original question is restated followed by a brief statement of the rational for the question.

I. Miscible Injection Project and MI Composition

3. What is the greatest pressure drop that a portion of a given MI slug is expected to see while it is in the reservoir? How is recovery effected if the pressure drop is greater than that projected? [NEW QUESTION FOLLOWS] What are the simulator predictions of the minimum and maximum reservoir pressures in each PBUMGP area during each year that MI is being injected?

RATIONAL This question is very important because the producers must guarantee that the MI will always remain miscible in the face of not knowing exactly what future pressure performance will be and what the pressure gradients in the reservoir will be. This is essential to a successful project because the MI designed NOW must remain miscible for up to 5 years (McGuire testimony, pp 259 line 20).

Furthermore, the producers offered testimony that they will design the MI composition for the lowest anticipated average pressure plus an additional 100 psi safety factor. For a given average reservoir pressure, there will be some parts of the reservoir at pressures higher than this average and some parts that are at lower pressures. How can the producers guarantee that their prediction of future reservoir pressure performance is accurate to +/- 250 psi? The consequences of falling below the miscibility are severe in terms of reduced displacement efficiency. Is the 250 psi really enough to guarantee miscibility at all times under all conditions?

7. How would gas sales of one billion cubic feet per day effect the availability of MI? How would gas sales of two billion cubic feet per day effect the availability of MI?

RATIONAL The producers answered that the effect is dependent on when gas sales began. So, rephrase the question to address the issue of liquid losses for a specific starting date and volume of gas sales; What would be the loss in ultimate liquid recovery if gas sales commenced in 1995, in 2000? At 1 bcf/d? At 2 bcf/d?

II. Fluid Properties and Gas Cap Properties

6. Under constant volume depletion conditions, i.e., a differential gas liberation process (as compared to constant overall composition conditions, i.e., a flash gas liberation process) what is the phase diagram for the gas cap gas at 4300 psia?--at 3600 psia?--at 3000 psia?

Under constant volume depletion conditions what portion of the retrograde liquids revaporize at some lower reservoir pressures? At what pressure does this revaporization begin? All else being equal, theory has it that more retrograde liquid is left in the gas cap at intermediate pressures relative to higher or lower pressures. Will this be true for the IPA? Is this retrograde phenomena exaggerated over time as the phase diagram for the gas cap gas is modified as the gas cap gas composition changes?

RATIONAL This question asks for routine phase behavior data for the gas cap gas. This is useful reservoir engineering data for understanding the behavior of the gas cap with changing pressure and temperature conditions over the producing life of the reservoir. How else is one to understand what is going on in the gas cap?

5. What is the current composition of the residual "black" oil saturation in the gas cap?--has it changed since 1977? What is the saturation of this fluid? How did the saturation get that low? What is the composition of the retrograde liquid that drops out of the gas in the gas cap? Will it change over time? Will the combined black oil and retrograde liquid saturation in the gas cap ever be high enough to allow the combined liquids to flow?

RATIONAL This question was not asked in its entirety. It needs to be reasked in order to understand why there is residual black oil in the gas cap and why the saturation value is currently so low. That is, why is the residual oil saturation so low. The point of the question in part was to demonstrate that the gravity drainage mechanism can be extremely efficient.

III. Reservoir Depletion Options and Alternatives

1. What are the basic assumptions contained in the base case that was used to evaluate the proposed reservoir depletion option over time, i.e., assumptions such as-- oil, CGF liquids and gas production rates, residue gas and MI injection rates, water injection rate, pressure behavior, injection and production well count, work over requirements, capital investment in new or modified unit facilities, off unit (or transfer between the IPA and Lisburne) gas and MI sales, sharing of IPA production facilities with other participating areas in or out of the unit, project life?

RATIONAL Rephrase the question to ask for the producer's simulator predictions for various possible depletion scenarios; for the following depletion cases and on a year by year basis what were the predicted well counts, oil production rates, GOR's WOR's, MI injection rates residue gas injection rates, condensate and CGF liquid rates, and average reservoir pressures?

1. the currently proposed plan,
2. the case of 2 bcf/d gas sales starting in 2000,
3. the case of stopping gas cycling immediately,

4. the case of stopping MI injection immediately (waterflood only in the MI areas)

If these cases were made available, the AOGCC and ADNR would have some basis for discussions of the producers' assumptions that went into these predictions as well as a fall for four different depletion alternatives and why the proposed plan before the AOGCC is the "best" plan.

3. Have the operators investigated using flue gas for reinjection? From a future gas sales perspective would it help to inject the CO₂ or flue gas or N₂ just in the apex wells and continue some injection of residue gas at the existing gas injection pad?

RATIONAL This was part of Question #3, but was not answered by the producers. They only addressed injection of N₂ or CO₂ throughout the gas cap.

4. Would ultimate liquid recovery benefit from increased availability of MI or residue gas? Is the MI recovery processes in the IPA rate sensitive or time sensitive?

RATIONAL The AOGCC eliminated this question. The question is important because it addresses two issues of the currently proposed depletion plan that the AOGCC is about to rule on: 1) what would be the priority between producing blendable CGF liquids versus manufacturing MI; 2) rate sensitivity is a fundamental question in any enhanced recovery process.

7. Is the gravity drainage recovery process enhanced, unaffected or slowed down by continued gas cycling? Will the gravity drainage process continue throughout the production life of the reservoir? What is the expected final residual oil saturation in the gravity drainage area?

RATIONAL The producers answered the question by saying that the gravity drainage is enhanced by the gas cycling due to the ability to produce high GOR wells. However, since it is the gas cycling (in part) that contributes to the high GOR's and if cycling were not done, the GOR's would generally be lower. Also, the higher gas saturations due to gas cycling slows down the gravity drainage by relative permeability effects.

We would like to rephrase this question to the following: Would the oil recovery from the oil zone in the gravity drainage area be the same if gas cycling operations were not being conducted? The point being to determine whether the black oil (not condensate) recovery in the gravity drainage area would be the same whether gas cycling was being conducted or not.

10. Would there be an increase in ultimate recovery of liquids from the gas cap by diverting all the available gas (including the MI) to the apex wells for reinjection? Or would this just accelerate the recovery process in the gas cap? Is there an urgency to recover liquids from

) the gas cap sooner verses later? Do the liquids recovered from just the gas cap have to be blended with black oil in order to be shipped down TAPS? Would the amount of gas liquids be large enough to support the operation of TAPS by themselves?

RATIONAL The first part of this question was not asked by the AOGCC. Since the Commission is charged with the prevention of waste and the question deals with an increase in ultimate recovery under a particular development option, the question seems appropriate in trying to understand the impacts of cycling the gas cap at the apex.

11. With respect to the potential for future off-unit gas sales, would cycling gas for longer periods of time at lower pressures result in the same liquid recovery as cycling gas for a shorter period of time at a higher pressure? What type of a gas cycling/EOR/gas sales/liquid recovery plan extends the life of TAPS the longest? Has the TAPS availability issued been studied?

RATIONAL This question was eliminated by the Commission. Without TAPS the oil production will have to be shut in. Waste may be created by not optimizing recovery prior to this shut in. DNR wishes to resubmit this question in the following form: Would cycling gas for longer periods of time at lower pressures result in the same liquid recovery as cycling gas for a shorter period of time at a higher pressure? What type of a gas cycling/EOR/gas sales in either 1995 or 2000/liquid recovery plan extends the life of TAPS the longest? Has the TAPS availability issue been studied?

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

RECEIVED

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

POUCH K - STATE CAPITOL
JUNEAU 99511

FEB 17 1977

February 14, 1977

Division of Oil and Gas Conservation
Anchorage

Mr. Hoyle Hamilton
Director, Division of
Oil and Gas Conservation
Dept. of Natural Resources
3001 Porcupine Drive
Anchorage, Alaska 99501

RE: ECONOMIC WASTE UNDER
AS 31

DI	
C.	
C. IN.	
1 ENG	
2 ENG	
3 ENG	
4 ENG	
5 ENG	
1 GEOL	K
2 GEOL	
3 GEOL	
PPV	
DRAFT	
SEC	
CONFER	
FILE	

Dear Hoyle:

You have asked if AS 31.05 permits the Conservation Committee to consider "economic waste" as well as physical waste. It is my conclusion that the Conservation Committee is allowed to consider economic factors in its establishment of conservation practices but that the term "economic waste" must be defined and the question related to a specific regulatory decision before a more meaningful legal opinion is possible.

I.

Brief History of Conservation Regulation

It will be helpful to an understanding of AS 31.05 to review briefly the history of oil and gas conservation regulation by states.* This is appropriate and useful because Alaska's conservation statute contains many of the same clauses and provisions found in the IOCC model statute and/or other state conservation statutes.

*/ This review is taken principally from S. McDonald, Petroleum Conservation in the United States: An Economic Analysis (1971); see also, Interstate Oil Compact Commission, A Study of Conservation of Oil and Gas in the United States (1964).

Initial conservation legislation was designed to prevent damage to other resources caused by oil and gas production and to eliminate certain obvious and easily preventable losses of natural gas. These initial conservation statutes usually established regulations applicable to individual wells (rather than whole reservoirs) and prohibited specific practices or conversely required certain specific practices, such as for example, requiring the proper casing and plugging of wells to prevent interchange of fluids among reservoir or the contamination of ground water supplies, or to prevent natural gas leaks. Later regulatory statutes usually retained the specific prohibitions of the earlier statutes but also included a general prohibition against waste which was defined in broad terms (or more often undefined). Thus, many state conservation statutes (including Alaska's) contain something of a collection of specific prohibitions and some rather broad, but undefined limitations.*

Conservation legislation, no doubt, was necessary because some operators in their haste to produce oil, employed poor production techniques and disregarded the impact of those practices on other resources (e.g. on ground water). However, another consideration was even more significant. Multiple ownership of the land overlying oil reservoirs combined with the rule of capture** to create an overpowering incentive for each owner of a lease to produce as

*/ AS 31.05.020 provides: "The waste of oil and gas in the state is prohibited." "Waste" is defined by AS 31.05.170(11) which because of its length is attached as appendix A hereto. R-100(14)

**/ The rule of capture says that whoever produces the oil owns it, regardless of where it is located underground. Railroad Commission v. Rowan & Nichols Oil Co., 310 U.S. 573 (1939).

much oil as rapidly as possible. This resulted in a number of production practices which frequently caused unnecessary capital expenditures and/or the loss of large quantities of oil. For example, since each producer was competing with other producers in the same reservoir he would usually drill as many wells as possible and operate each well as long as possible. This meant that more wells would be drilled than were actually required to produce all the oil which could be produced from a reservoir; and even more significantly, it usually meant reservoir pressure would be rapidly depleted resulting in less total oil being produced from the reservoir than could have been produced if production had been coordinated. Similarly, large quantities of oil were lost in above ground earthen storage reservoirs which were used because they were the fastest and cheapest way to store the rapidly produced oil. The more modern regulatory statutes (those enacted or amended after 1930) were intended to give state regulators more power to control production practices so as to prevent losses of oil and gas resulting from the competitive race to produce oil as rapidly as possible from each reservoir.

The methods of production control employed by various state regulators have involved a number of overlapping and/or alternative approaches. One of the earliest approaches and also one of the simplest and most widely accepted regulatory methods has been to control the number and spacing of wells. Every state which has a conservation statute expressly authorizes the control of well spacing.* A second method of regulation has been to control directly the quantity of oil and/or gas produced. In practice, this type of regulation has

*/ IOCC, A Study of Conservation of Oil and Gas in the United States, at 180 (1964).

taken two distinct forms, each of which will be discussed in greater detail below. A third method of regulation has been to authorize voluntary or compulsory unitization, and a fourth method of regulation has been to require the use of secondary recovery techniques. Many state statutes authorize one or more of these methods (several authorize all four methods), with individual states relying to varying degrees upon each method.

Direct Control of Production and "Economic Waste"

In the early years of the industry, the price of oil often was very low because producers, in their haste to capture as much oil as possible, frequently produced oil far in excess of market demand. Low prices, of course, meant little profit for the industry and also little revenue for those states which depended heavily on royalty payments and taxation of the oil industry for their income. Out of this situation emerged the concept of "economic waste", that is, the production of oil (or gas) in excess of market demand. In 1915 the Oklahoma conservation statute was amended to prohibit "economic waste" (which was not defined) and on the basis of that language, the Oklahoma regulatory agency adopted a regulatory scheme which allowed the agency to establish a statewide production limit and allocate production back to each well so that total production would not exceed that limit. Although this method of regulation effected prices (many persons charged it fixed prices), limiting production to market demand was found by the courts to be a valid method of preventing waste. Julian Oil and Royalties Co. v. Capshaw, 292 P. 841 (1930); Champlin Refining Co. v. Oklahoma Corp. Commission, 286 U.S. 210 (1932). In Texas, a 1929 amendment to the conservation statute expressly stated that the prohibition against waste was not to be construed to mean "economic waste."

After the 1929 amendment, suits were filed challenging Texas's policy of limiting oil production to market demand. In one case, the court held Texas' regulatory approach valid despite the statutory reference to "economic waste." Danciger Oil and Refining Co. v. Railroad Commission, 49 S.W.2d 837 (1932). In a second case, however, the court held that the Railroad Commission's orders were intended to prevent "economic waste", and that this was in violation of the 1929 amendment. Alfred Macmillan v. Railroad Commission, 51 F.2d 400 (1931). In response to the MacMillan decision, the Texas legislature repealed the reference to "economic waste" and authorized the prohibition of "production of crude petroleum oil in excess of transportation or market facilities or reasonable market demand". Since the MacMillan case, the practice has been to avoid use of the term "economic waste" in conservation statutes.* Rather those states which employ a market demand method of production control have adopted such a regulatory policy through the use of language similar to that in the Texas statute.**

In the light of the above legal history, it is my conclusion that the term "economic waste", when used in reference to oil and gas conservation practices, is best understood to mean regulation which limits production to market demand.***

*/ Only four state statutes use the term "economic waste." The Oklahoma and Kansas statutes each prohibit "economic waste", while the statutes of Illinois and Kentucky prohibit limitation of production to prevent or control "economic waste." 10CC, at 188-89.

**/ Ibid. at 176-79.

***/ One commentator has written: "Despite its apparent breadth, the term 'economic waste' is usually employed narrowly to mean the sale of oil or gas at a price below full cost or actual value and/or the use of oil or gas in ways which fail fully to exploit its intrinsic value". S. McDonald, Petroleum Conservation in the United States; An Economic Analysis 127 (1971).

II.

While the above discussion answers the question you have asked, I believe it might be helpful to discuss "economic waste" as the term might be defined or perceived by others. This discussion, because it is unrelated to any particular regulatory problem is general.

Direct Production Control and
the Maximum Efficient Rate of Production

In those states which do not employ a market demand method of production regulation, production is regulated on a reservoir-by-reservoir basis, with total production from a reservoir being limited to the maximum efficient rate (MER). Typically, the MER is determined with respect to engineering factors rather than economic considerations. Thus, the MER is that rate which will maximize the total output of oil (in an oil reservoir). A rate which causes total oil production to diminish (because, say reservoir pressure is dissipated too rapidly) will be in excess of the MER and will not be allowed. Once the MER is established, shares of production are allocated to each producer and/or well.

Although in practice, engineering considerations have dominated the determination of the MER, it is clearly possible that economic criteria could equally be used as the efficiency criteria. If this were done, the regulatory agency might establish rates designed to maximize total present value rather than total output. Thus, at a time of declining real prices for oil (or perhaps ever slowly rising prices) the regulator might well determine that the MER was at a rate which

sacrificed future oil production for increased present production.*

There is certainly nothing express in AS 31.05 which would prevent the Conservation Committee from implementing production control using economic, rather than engineering criteria, to determine the MER. Indeed, words such as "unnecessary", "inefficient", and "excessive" might well connote economic criteria (at least to an economist) rather than engineering criteria. Nevertheless, I believe use of economic criteria, rather than engineering criteria, would represent a drastic change in regulatory practice in Alaska (and anywhere else for that matter) and thus, should only be undertaken in response to clear legislative directive in the form of amendments to the conservation statute.

I do not agree since the terms "physical waste" & "underground waste" are in the definition.

Having noted that the regulatory practice in Alaska and elsewhere is to use engineering, rather than economic criteria to determine the MER, it should not go unstated that economic considerations are involved in many conservation decisions at least in a gross sense. For example, where the Conservation Committee is considering whether to require a water injection program, it certainly must compare the cost

*/ The most striking difference between the use of engineering criteria and economic criteria may occur where a reservoir contains both oil and non-associated gas, and the production of one results in a diminshment of the other which can be produced. In that case, engineering criteria might call for maximization of total hydrocarbons (BTU's) while economic criteria would call for consideration of the present and probable future value (price) of each and maximization of the present value.

It should be noted that this is not the regulatory problem you face with the Prudhoe Bay field, since (based on my understanding) hydrocarbon production can be maximized provided gas production is held within reasonable bounds (which bounds may be zero if water flood is not employed; however, in that event, the field can be blown down once oil production ceases). Thus, if one is willing to indulge the assumption that gas prices will increase at a rate at least equal to the discount rate, the MER will be the same using either engineering or economic criteria.

RECEIVED

FEB 23 1977

Division of Oil and Gas Conservation

of such a program with the expected increase in recovered hydrocarbons. In doing so, the Conservation Committee need not adopt the economic criteria used by the producers, thus, a water injection program which the producer did not wish to undertake because the rate of return was too small (in their opinion) might still be required by the Conservation Committee. However, in the extreme case, where costs greatly exceeded any possible economic benefits to be derived, constitutional limitations likely would prevent the Committee from requiring an injection program.

Unitization of a Reservoir

One commentator has concluded that state conservation statutes "should require unitization of every oil reservoir within a reasonable time following discovery", and that such a statute "should supplant all present regulations (e.g. of well spacing and production rates) except those designed to protect other resources from damage by oil operations." The conclusion is incorrect because it embodies a false assumption (which will be discussed below) but it nevertheless highlights an important consideration. That is, by eliminating the competition among producers of oil from a reservoir, one eliminates most of the incentive to engage in "wasteful" practices. In a unitized reservoir, all producers will be better off if production is maximized.

If a unitized reservoir was unregulated, production rates would be determined in accordance with procedures adopted by the unit participants. In such case, one would expect the unit participants acting as profit maximizing entities to produce the reservoir in a fashion which

*/ S. McDonald, Unit Operation of Oil Reservoirs as an Instrument of Conservation, 49 Notre Dame Lawyer 305 (1973).

maximized the reservoir's present value.* Such rate of production likely would not correspond to the MER as determined by engineering principles. The public's interest ~~interest~~ in the production of nonrenewable oil and gas resources will correspond exactly with the producers' interest only in the hypothetical world of economists where competition is infinite and institutional constraints non-existent. In practice, the public's interest may be served by requiring the operators of a unitized reservoir to operate at a rate different from that which they would choose on their own. For example, the unit operators may decide against fluid injection because the anticipated rate of return is too low (in their view). The public's interest, however, might best be served by requiring an injection program. Or to give another example, where oil prices are controlled, maximization of present value by the producers likely will run counter to the public's interest.

Regulators of unitized fields have in the past required maximization of hydrocarbons while considering at least in gross terms economics factors. As before, regulators could well require maximization of other objective criteria. However, I would not advise such a course of action without clear Legislative direction in the form of amendments to the present conservation statute.

*/ For various reasons in practice production rates may not be such as to maximize present value. For example, integrated producers may be facing crude shortages and willing to sacrifice future revenues while others may face a glut situation. The actual rate may represent a compromise. Some producers may want to hold back production to speculate on future market conditions, while others may prefer to follow less venturesome corporate policies. In short, producers may each have different discount rates.

Mr. Hoyle Hamilton, Director
Div. of Oil and Gas Conservation

February 14, 1977
Page 10

Sincerely,

AVRUM M. GROSS
ATTORNEY GENERAL

Frederick H. Boness

By: Frederick H. Boness
Assistant Attorney General

FHB:bvd

SCOMM

79:8

Representative Kay Brown

ALASKA STATE LEGISLATURE

Legislative Information Office
3111 C Street #435
Anchorage, Alaska 99503
(907) 561-7627

During Session
P.O. Box V
Juneau, Alaska 99811
(907) 465-4998

TO: Representative Bill Hudson, Chair
House Oil and Gas Committee

FROM: Representative Kay Brown

DATE: February 6, 1992

SUBJ: HB 433/AO&GCC and the Definition of Waste

In anticipation of the House Oil and Gas Committee's consideration of HB 433, legislation concerning the Alaska Oil and Gas Conservation Commission and the definition of "waste," please find attached the following materials.

1. Sponsor Statement
2. Sectional Analysis
3. "Petroleum — An Overview of the Industry"
Alaska Department of Commerce and Economic Development
4. Legal Opinion
Frederick Boness/Assistant AG to Hoyle Hamilton/AO&GCC
5. Presentation to the House Finance and House Oil & Gas Committees
Kevin Meyers/ARCO Alaska, Inc. & Dave Szabo/BP (excerpt)
6. News Articles —
"Hickel plans to test market for gas"
Anchorage Daily News (January 23, 1992)
"Engineers warn against loss of Prudhoe oil"
Anchorage Daily News (January 24, 1992)

It is my understanding that the Alaska Oil and Gas Conservation Commission will be preparing a fiscal note for this legislation and will submit that fiscal note under separate cover.

If you have any questions concerning this legislation, please let me know or contact Eric Myers of my staff at 465-4998.

attachments

DISTRICT 12

Downtown • Fairview • City View • Bootleggers Cove • Inlet View • South Addition • Thunderbird Terrace
Eastridge • Penland Park • Airport Heights • Government Hill

printed on recycled paper • 100% •

SPONSOR STATEMENT

House Bill 433 — AO&GCC and the Definition of Waste

House Bill 433

House Bill 433 expands the statutory responsibilities of the Alaska Oil and Gas Conservation Commission (AO&GCC) to address issues concerning the public interest in achieving maximum oil and gas recovery.

In determining whether "waste" exists, the AO&GCC shall specifically consider 1) the economic value of oil and gas that may be left behind in a reservoir; 2) the cost of recovering those resources; and 3) the public interest in achieving maximum recovery.

Consideration of Economic Factors Under Current Law

An advisory legal opinion issued by the Alaska Attorney General in 1977 concluded that the AO&GCC is allowed to consider economic factors in its establishment of conservation practices. (Boness to Hoyle, February 14, 1977). However, the opinion also suggests that further direction from the legislature would be appropriate to eliminate ambiguity regarding the AO&GCC's consideration of the public economic interest in maximizing field production.

In short, while it appears that AOGCC use of economic criteria is permissible under state statute, it is not present practice for the AO&GCC to expressly consider the public's economic interest in maximum field recovery.

The Public Interest in Maximum Oil & Gas Recovery

The public interest in maximum feasible and economic oil recovery from Alaska's oil and gas resources is compelling.

The economic significance of oil and gas development in Alaska is well documented. The petroleum sector accounted for more than a third of Alaska's state product in 1987. Oil and gas development and production activities account for a substantial fraction of total state employment. The petroleum sector directly employed over 10,000 workers in 1988 and accounted for 5% of the state's employment. The same year, it paid over \$600 million, or 10 percent, of the state total in wages and salaries. Approximately 85% of the state's revenue comes from oil and gas royalties and taxes.

The public interest in Alaska petroleum development extends beyond the economic impact of oil and gas development experienced in the state. There are substantial national, even international, interests in Alaska oil and gas development. The Prudhoe Bay oilfield is by far the largest oil field in North America — it accounts for approximately 20% of U.S. oil production and more than 3% of world oil production. As evidenced by the U.S. war with Iraq, the continued supply and availability of hydrocarbon resources is a fundamental matter of national security.

Prudhoe Bay Natural Gas Development

As indicated during recent hearing sponsored jointly by the House Oil and Gas Committee jointly with the House Finance Committee, alternative Prudhoe Bay reservoir development strategies may significantly impact the maximum achievable recovery from the reservoir.

During those hearings, testimony was presented indicating that premature, large-volume natural gas sales from the Prudhoe Bay reservoir might adversely impact the long-term recovery of oil from Prudhoe Bay. As much as a billion barrels of recoverable oil could be left behind if large-scale gas sales started by 1997, according to industry experts who testified at the hearing.

There is a compelling public interest in assuring that development of the Prudhoe Bay reservoir achieves the maximum recovery that is economically and technically feasible. While there might be substantial short-term economic benefits that would result from sale of Prudhoe Bay gas and the development of a gas line project, the value of those developments should be considered in light of long-term recovery of all hydrocarbon resources from the reservoir. If a large volume of oil were to be "left behind" in the Prudhoe Bay reservoir as a result of large volume gas sales and reduced field pressures, the net benefit to the public of gas sales could well be negative.

House Bill 433 would provide the AO&GCC clear direction to safeguard the public's economic interest in reservoir development decisions.