

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILE 8672
2023 SCOMM 78: SENATE SPEC. COMM. ON OIL & GAS, 1991-1992

ALLOCATION**TOTAL****OBLIGATED****EXPENDED**

Exxon Valdez Litigation, RSA to Law	3,653.1	3,653.1	529.4
Arctic Marine Resources Commission	100.0	100.0	50.0
Spill Reserve	12,627.4		
Soldotna Chlorine Gas, Sewage Treatment Plant		10.0	0.0
Kodiak Landslide Spill, Storage Tank and Fuel Line Damage		7.0	4.8
Chevron Kenai Oil Spill, Cook Inlet Spill		25.0	1.5
208 Wendell Street, Fairbanks, Oil Spill		4.0	0.0
East Sound, Oil Spill, Unalaska		5.7	5.7
Benny Benson Lagoon, Underground Storage Tank Oil Spill, Seward		25.0	24.2
Prince William Sound Regional Citizens' Advisory Council			
Ballast Water Treatment Contract	175.0	175.0	0.0
Non Crude Tanker Study	30.0	30.0	20.0

OTHER AGENCIES

Citizen's Oversight Council on Oil and Other Hazardous Substances	237.3	237.3	204.9
Ferries with Oil Spill Response Capabilities (SB165)	500.0	500.0	4.1

Note 1: SPAR Director's Office has expended 11.2 which has yet to be distributed to the RSAs.

Note 2: Administrative Services has not expended or recorded any Response Fund eligible costs to date.

Note 3: RSA is in process awaiting approval of Revised Program 18920106.

Note 4: RSA is in process awaiting approval of Revised Program 18920106.

Note 5: Law has expended 210.0 which has not been distributed amongst the three allocations funding cost recovery efforts.

Note 6: RSA is in process.

Note 7: Adjustments will be processed to correct apparent over expenditures.

Note 8: Adjustments will be processed to correct apparent over expenditures.

Note 9: Adjustments will be processed to correct apparent over expenditures.

Note 10: Unable to determine University of Alaska actual expenditures.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Proposed Reductions in FY 93 Operating Requirements

Component Option	Impact on Positions	GF Savings/ (Cost)	Fund Change	Revenue Earnings/ (Loss)	Required Changes*	Affected Population	Comments
DIVISION OF ENVIRONMENTAL QUALITY (continued)							
Solid & Hazardous Waste Mgmt.	-3	265.1	None	0	None	Southcentral and Northern Regions	Combine resources with local communities; Reduce solid waste planning grants by \$50.0. We will not be filling currently vacant positions.
Air Quality Management	-1	118.9	None	0	None	Northern Region Statewide	Reduction in Ambient Air monitoring. Data enhancement program eliminated.
Water Quality Management	0	80.2	None	0	None	General reduction in activities Statewide	Reduction of monitoring.
DIVISION OF SPILL PREVENTION AND RESPONSE							
Director's Office	0	0.0	None	0.0	None	None	
Spill Prevention, Planning and Management	-1	70.0	Yes	0.0	46.04.210 46.08.040	Local Government Fire and Police Regional Response Team	Rely on State Master Plan and local emergency plans developed by LEPC's for regional contingency planning.
Spill Response Office	-4	230.0	Yes	0.0	46.08.100 thru 190 46.13.010 46.13.040 46.13.110	State Employees Central Office	Localize Hazardous Materials response, combine functions with DMVA-DES; Balance of Staff to Dedicated Response Positions in Regions and Centralized Spill Management Unit.
Contaminated Sites	0	0.0	None	0.0	None	None	
Storage Tank Assistance Fund	0	700.0	None	0.0	46.08.040	None	Reduce total operating budget for Storage Tank Assistance Program from 6,700.0 to 6,000.0. Reduction in Grants. General Fund program receipts fund 500.0. The balance 5,500.0 is requested from the Response Fund
TOTAL NON-FORMULA PROGRAMS	(17.0)	2,400.0		275.0			
FORMULA PROGRAMS							
TOTAL FORMULA PROGRAMS	(17.0)	2,400.0		275.0			

NOTES:

* S=Statute;R=Regulation;P=Policy

** Denotes Formula Program

CITY OF WHITTIER, ALASKA
RESOLUTION 289-92

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF WHITTIER, ALASKA URGING THE STATE LEGISLATURE TO INCLUDE THE REGIONAL CITIZENS ADVISORY COUNCIL PROPOSED NEARSHORE STRIKE TEAM DEMONSTRATION PROJECT

WHEREAS, the City of Whittier is a member of the Regional Citizens Advisory Council (RCAC); and

WHEREAS, the City of Whittier supports the concept of an Alaska Coastal Committee Cooperative for the response to oil spills; and

WHEREAS, the RCAC proposed Nearshore Strike Team Demonstration Project will enhance the ability of local people to participate in the production of the resources upon which coastal communities depend; and

WHEREAS, the Nearshore Demonstration Project will begin to meet the requirements of Senate Bill 264, passed in 1989, (AS 46.08.110), which mandates the establishment of oil and hazardous substance spill response equipment depots and volunteer response corps; and

WHEREAS, the proposed Demonstration Project is an appropriate use of 470 funds.

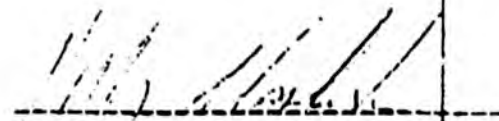
NOW, THEREFORE, THE WHITTIER CITY COUNCIL REQUESTS:

THAT the City of Whittier urges the state legislature to include the RCAC proposed Nearshore Strike Team Demonstration Project.

PASSED AND APPROVED by duly constituted quorum of the Whittier City Council on this 16th day of March, 1992.

ATTEST:


Deputy Clerk


Kelly Carlisle, Mayor

CITY OF WHITTIER, ALASKA
RESOLUTION 291-92

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF WHITTIER, ALASKA REQUESTING THAT THE ALASKA STATE LEGISLATURE AMEND AS 43.40.010 (F) TO REFUND THE PROCEEDS OF THE REVENUE FROM TAXES ON MOTOR FUEL USED IN BOATS AND WATER CRAFT TO MUNICIPALITIES

WHEREAS, Alaska is one of the major fishing and pleasure boating areas in the United States; and

WHEREAS, Whittier is a major fishing port in Alaska and the United States; and

WHEREAS, Whittier also attracts the pleasure boaters, both locally and from the southern forty-eight (48) states; and

WHEREAS, Whittier has a waiting list of 236 to obtain moorage in the harbor with only a 330 slip harbor; and

WHEREAS, Whittier manages the small boat harbor; and

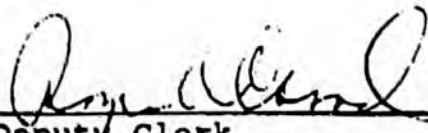
WHEREAS, all of the harbors and port facilities in Alaska are in dire need of additional funding.

NOW, THEREFORE, THE WHITTIER CITY COUNCIL REQUESTS:

THAT the Alaska State Legislature amend AS 43.40.010 (F) to provide that the proceeds from the revenue on the tax on motor fuel used in boats and water craft of all descriptions be refunded to the municipalities from which such revenue is generated.

PASSED AND APPROVED by duly constituted quorum of the Whittier City Council on this 16th day of March 1992.

ATTEST:


Deputy Clerk


Kelly Carlisle, Mayor



Maritime Helicopters

March 17, 1992

Alaska State Capitol
Senate Finance Committee
Juneau, Alaska 99811

Gentlemen:

We are in support of the Prince William Sound Regional Citizens Advisory Council and urge funding of the Nearshore Strike Team Demonstration Project.

We understand DES funds are available for training six coastal communities, as well as making available an equipment cache for spill response.

Respectfully,

Donald M. Fell

Donald M. Fell



Karl Pulliam
Board of Directors
11355 Frontage Rd.
Suite 228
Kenai, AK 99611
(907) 283-7222
Fax (907) 283-6102

March 26, 1992

REGIONAL CITIZENS ADVISORY COUNCIL

Sen. Pourchott;

My name is Karl Pulliam, City of Seldovia Rep on Cook Inlet's RCAC. I would like you to know I just completed a 3 day training with SERVS, the Prince William Sound escort and response group. There were 109 fishermen here in Seldovia to go through the training. We were impressed with SERVS, we like being part of the team. Fishermen are not only a viable response resource, they are the bulk of the expert on water personnel in any spill! This demonstration project for a Nearshore Strike Team is essential to gaining the trust and commitment of fishermen statewide. We will make it successful--highly successful! One hundred and nine of us proved ourselves with SERVS on the water 2 days ago... DEC is the entity that can open the door of the 470 fund to the people it was meant to serve. There isn't a fishermen who wants to see that money sit idle until another spill. We must have more training. We must have accessible equipment. We must have the funds to do this...And we must have it from this legislative session! If you want to replace complacency with enthusiasm, replace distrust with willingness, and replace broken bridges between the fishing and oil industry...then fund the Nearshore Strike Team Project. If you need a model group to work within an area of high risk, try the SOS TEAM in Cook Inlet. Cook Inlet is your next accident waiting to happen!

Sincerely,

Karl Pulliam
City of Seldovia Representative
Cook Inlet RCAC



Regional Citizens' Advisory Council 601 West Fifth Avenue, Suite 500 Anchorage, Alaska 99501-2254 / (907) 277-7222 / FAX (907) 277-4523

March 24, 1992

Pat Pourchot
Senator
Alaska State Legislature
P.O. Box V, Rm 516
Juneau, AK 99811

Dear Senator Pourchot:

During your deliberations on the DEC budget, the 470 Fund, and how best to implement the need for spill response capability in Alaska, we encourage you to support the Nearshore Strike Team Demonstration Project as outlined in the attached proposal. The proposal was presented to the Joint House Senate DEC Budget Subcommittee and was favorably received. It is also supported by DEC's Spill Prevention and Response Director, several fishing groups, and coastal communities around the state.

The project would be managed by the State as an open bid process, selecting the best proposal to implement a model nearshore strike team equipment cache, training for six coastal communities, a statewide data base of vessels and responders, development of model contracts and a public information program. The project will develop a network of local spill responders who can protect nearshore resources in the event of a major crude oil spill. It can also use those same local responders and equipment for responding to small non-crude spills in localized areas. RCAC requests that the demonstration nearshore strike team be located in an area of greatest risk of a TAPS spill.

The response depots and corps provisions of SB 264 (AS 46.08.110) came about in recognition of the important role volunteers can play in an oil spill cleanup. During the *Exxon Valdez* oil spill, fishermen and other local volunteers played a critical and essential role in booming off critical areas, such as hatcheries and intertidal zones. But a great deal of time was lost because there was no recognition of volunteers and no pre-coordination of equipment and volunteer response resources. The goal of SB 264 was to make sure that volunteers are better coordinated and utilized in the event of future spills.

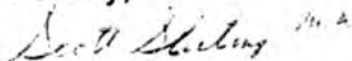
The Division of Emergency Services (DES) is presently the state agency charged with implementing the oil and hazardous substance response depots and corps provisions of SB 264. To date, while DES has received over \$2 million in funding,

there are still no response corps or depots organized. For the FY 93 budget, there is another \$2 million for DES to continue the development of its depots and corps. DES has stated that its first priority for this effort will not be oil spills, but rather hazardous substance releases. While RCAC supports the development of response depots for hazardous substances, we would like to see response depots and corps for oil as well.

The attached proposal provides an inexpensive method to begin implementing the oil spill response depots and corps that were adopted in 1989 as part of SB 264. It would cost approximately \$900,000 funded from the Oil and Hazardous Substance Release Response Fund.

We would appreciate your support to fund the Nearshore Strike Team Demonstration Project. Please call me at 277-3533 if you have questions regarding the attached proposal.

Sincerely,



Scott Sterling, President
Regional Citizens' Advisory Council

cc:

Sheila K. Gottehrer, RCAC Executive Director
RCAC Members



Oil Reform Alliance

March 17, 1992

Senator Pourchot, Chair
Senate DEC Budget Subcommittee

Representative Brown, Chair
House DEC Budget Subcommittee

Dear Senator Pourchot and Representative Brown;

The Oil Reform Alliance would like you to consider use of 470 Funds to increase DEC oversight of ballast water operations in Valdez.

In 1976 prior to commencement of shipping operations from the TAPS terminus in Valdez, the Alaska Legislature passed SB 406 (SLA 1976). In part, this new law required payment of annual risk charges by terminal operators and vessel owners into a Coastal Protection Fund to pay for ADEC's administrative, enforcement and clean-up expenses, and research on spill prevention and removal 1/. During the three years this law was in effect, a tanker and oil terminal oversight program was created (with a separate line item in the budget) which, by 1979, funded seven new full time positions, including three in Valdez 2/.

However, by 1981, the Coastal Protection Fund was eliminated (*Chevron v. Hammond*) and the seven tanker and oil terminal oversight positions were distributed to other offices 3/. After successfully gutting of the key provisions of the Oil Discharge Prevention and Pollution Control Act, the oil "industry encouraged the view that it should be allowed to take care of its own safety matters; that state activity was a needless and obstructionist interference with private prerogative; and that left to its own devices the industry would employ the best available technology with the optimum commitment of resources" 5/.

In 1988, Port Valdez was declared a "toxic impaired waterway" by the state due to documented hydrocarbon pollution from the Alyeska terminal.

In 1991, for the second time in six years, the legislature held oversight hearings and EPA and DEC conducted investigations on Alyeska terminal and TAPS tanker operations regarding ballast water practices. For the second time, problems were identified

1/ Alaska Oil Spill Commission. Feb. 1990. Spill: The Wreck of the Exxon Valdez. Vol. 3, Appendix M, No. 4.2, p. 16-22.

2/ Alaska Oil Spill Commission. Feb. 1990. Spill: The Wreck of the Exxon Valdez. Vol. 1, Appendix E, p. 20.

3/ Ibid.

5/ Alaska Oil Spill Commission. Feb. 1990. Spill: The Wreck of the Exxon Valdez. Final Report. P. 137-143.

with offshore discharge of ballast water and with disposal of toxic and hazardous substances into the Alyeska facility (BWT). For the second time, EPA and DEC recommended solutions to control or abate disposal of undesirable (i.e., "untreatable") substances through the BWT. The regulatory agencies had not followed through with their earlier recommendations.

Past experience proves that solutions will not be effective without full time DEC personnel overseeing terminal and tanker operations in Valdez on a daily basis as the legislature originally intended. The legislature allotted three full time DEC inspectors when pipeline throughput was less than half what it is today. In 1989, DEC sought funding to provide a terminal and tanker oversight program in Valdez which would include inspection of 20% of all tankers visiting Alyeska. The 20% rate was a significant drop from the 50% goal set by DEC a decade earlier, yet DEC has failed to achieve even their reduced standard of inspection.

The logical funding source for three DEC oversight positions is the 470 Fund for two reasons. First, this recreates the "user fee" concept of the original Coastal Protection Fund. Since passage of the Oil Pollution Act of 1990, it is clear Congress no longer intends to override more stringent state regulation and the way is open for the state to reassert its historic role in resource protection 6/. Secondly, because DEC oversight is critical to preventing long-term chronic pollution from tanker and BWT operations, the positions should be insulated to some degree from the political whims of the temporary occupant of the governor's office.

The Oil Reform Alliance is concerned that lack of sufficient DEC oversight is a major contributing factor to the pollution problems in Port Valdez. The Alyeska terminal operates 24 hours a day, 7 days a week: DEC oversight should be proportioned accordingly. Without sufficient full time DEC oversight of tanker and BWT operations, the marine-generated wastes associated with 22% of the U.S. domestic crude supply will continue to be disposed of in Port Valdez--with potentially disastrous environmental and economic consequences.

Sincerely,

Riki Ott

Riki Ott
President

cc: Sen. Duncan, Jones, Kertulla, Menard
Reps. Koponen, Kubina, Leman, Nevarre

6/ Recommendation 11 of the Alaska Oil Spill Commission states: "The state should adopt stringent standards regulating the transportation of oil in its own waters without fear of federal preemption." Final Report, p. 138.

SELDOVIA NATIVE ASSOCIATION, INC.

P.O. DRAWER L

SELDOVIA, ALASKA 99663

(907) 234-7625 • 234-7890

March 16, 1992

Hon. Sen. Jay Kerttula, Co-Chairman
Hon. Sen. Pat Pourchot, Co-Chairman
Senate Finance Committee
Pouch V
Juneau, AK. 99811

Dear Senators,

The Seldovia Native Association, Inc. (SNA) and Seldovia Village Tribe (SVT) support **THE NEARSHORE STRIKE TEAMS DEMONSTRATION PROJECT.**

This is a project that can be funded with monies from the 470 fund which is already in place. Using this available fund, this project will not need any funding from the State operating or capital budgets.

We highly recommend the S.O.S team based in Seldovia be the designated organization for this project.

Seldovia is the ideal place for such a strike team. A lot of equipment and effort has been placed on the port of Valdez and it's tanker route since the disastrous "EXXON VALDEZ" oil spill. These efforts are to be commended.

Yet there is as great a need to have "Strike Teams" prepared in the down stream flow area, in the event of another spill or regardless of the size. The recent Cook Inlet spill is a good example of this.

Six communities are ready to form "Strike Teams". With the SOS Team in place, and it's willingness to participate, Seldovia is the optimum location for this project to start and be the model for other coastal communities.

The port of Seldovia is between the Port of Valdez and the Cook Inlet oil facilities as well as the Kodiak and Shelikof Straits area. Seldovia can respond to any area, it has done so in the past.

The near shore strike team based in Seldovia can be put together without any lost time trying to form a new group or organization. The S.O.S. team is organized and ready to serve.

**MULTI-PURPOSE REPLACEMENT VESSEL
TALKING PAPER**

Revision 2.2

March 26, 1992

**ALASKA MARINE HIGHWAY SYSTEM
DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES
STATE OF ALASKA**

DRAFT

CORRECTION

**THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY**

SELDOVIA NATIVE ASSOCIATION, INC.

P.O. DRAWER L

SELDOVIA, ALASKA 99663

(907) 234-7625 • 234-7890

March 16, 1992

Hon. Sen. Jay Kerttula, Co-Chairman
Hon. Sen. Pat Pourchot, Co-Chairman
Senate Finance Committee
Pouch V
Juneau, AK. 99811

Dear Senators,

The Seldovia Native Association, Inc. (SNA) and Seldovia Village Tribe (SVT) support **THE NEARSHORE STRIKE TEAMS DEMONSTRATION PROJECT.**

This is a project that can be funded with monies from the 470 fund which is already in place. Using this available fund, this project will not need any funding from the State operating or capital budgets.

We highly recommend the S.O.S team based in Seldovia be the designated organization for this project.

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The near shore strike team based in Seldovia can be put together without any lost time trying to form a new group or organization. The S.O.S. team is organized and ready to serve.

As a land owner in the area of potential risk, the SNA cannot stress too highly the need for these near shore strike teams. The funding is available. The S.O.S. team is ready and willing. Please support this project.

If we can be of any assistance or answer any questions please contact us at your convenience.

Sincerely,

Fred H. Elvsaas

Fred H. Elvsaas President
Seldovia Native Association, Inc.
Seldovia Village Tribe.

cc: All Legislators

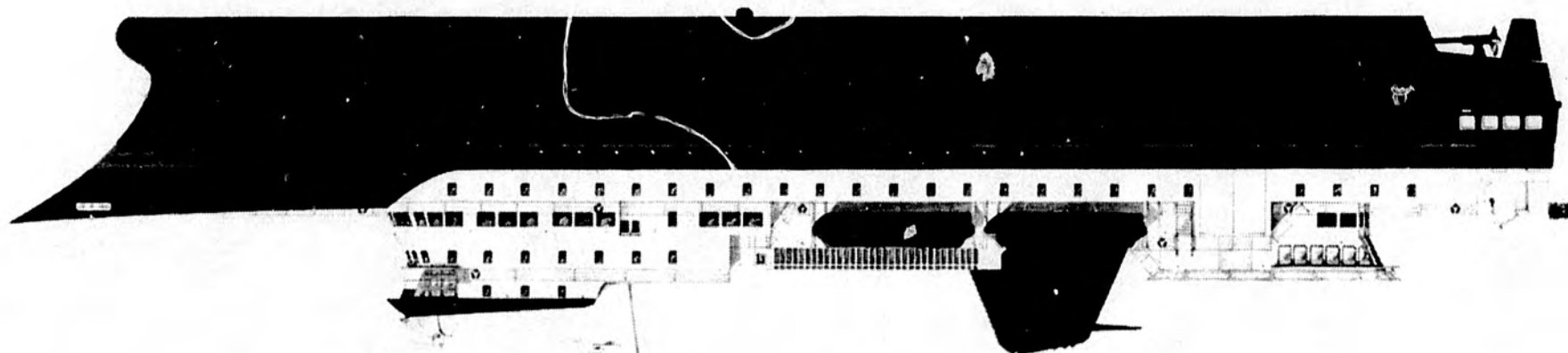
**MULTI-PURPOSE REPLACEMENT VESSEL
TALKING PAPER**

Revision 2.2

March 26, 1992

**ALASKA MARINE HIGHWAY SYSTEM
DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES
STATE OF ALASKA**

DRAFT



INDEX

Introduction.	1
The Mission	
Mission Statement	2
Mission Requirements.	2
The Design Process	
Design Schedule	5
Step One - Initial vessel parameters	
Vessel particulars.	6
Vessel Arrangements:	
Profile	7
Main Deck - 1 Deck	8
2 Deck - 3 Deck	8
4 Deck - 5 Deck	9

NOTICE

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INTRODUCTION

This paper describes the design process for the new Alaska Marine Highway System (AMHS) replacement vessel. Because of the need for employee and public involvement in the vessel design process, this paper is formulated to be a progress statement, presenting vessel characteristics as they are identified during the design process. As such, this paper varies with each edition; the vessel design loose and sketchy at first, becoming solid construction details at the end.

Because clear mission requirements are the fundamental basis of design, this paper presents the latest set of mission requirements, including a list of particulars and arrangements for each deck, for the new AMHS vessel.



MISSION STATEMENT

The new AMHS vessel will be required to successfully carry out the marine highway function, on the following routes, according to existing published schedules and:

*serve as a S.E. mainline vessel for 4 or 5 months per year,
must be able to complete 10 to 12 cross gulf trips between S.E. and S.W. a year,
provide limited S.W. service when the M/V Tustumena is in overhaul,
provide emergency response capability.*

MISSION REQUIREMENTS

The intent of the mission requirements section is to define the mission statement into engineering parameters.

The Marine Highway Function Requirements

Accommodate legal highway vehicle traffic (with length restrictions), with car deck capacity no smaller than Taku
Comfortably accommodate maximum number of passengers, both walk on and drive on, with:

- Maximum seating/viewing space
- Maximum number of staterooms per vehicle lane
- Amenities to provide a comfortable 1 to 7 day trip
- Maximum number of reasonably priced lodgings
- Flexible public space utilization
- Access for physically challenged
- Family oriented

MISSION REQUIREMENTS CONTINUED

Other General Vessel Requirements

- U.S Flagged
- U.S Coast Guard, 46 CFR subchapter H, Approved
- American Bureau of Shipping, +A1, approved
- Same life saving appliances, and fire fighting equipment, as fleet standard
- Maximize equipment similarity with existing fleet, consistent with current technology
- Maximize vessel automation, to minimize operational costs
- 64 year life span, through 1 re-engining, and two hotel refurbishment
- High reliability
- Low maintenance
- Proven technology
- Maximize revenue potential

South West/South Central System - Requirements

- Ocean rated
- Dock, unassisted, at:
 - Yakutat
 - Valdez
 - Cordova
 - Seward
 - Homer
 - Kodiak
 - King Cove
 - Sand Point
 - Cold Bay
- Dutch Harbor, in the following conditions:
 - all tidal conditions,
 - all current ranges,
 - winds stead at 35 to 40 knots, gusting to 50,
 - all visibility conditions,
- Operate in serve arctic conditions
- No Ice rating on hull strength
- Speed adequate to make schedule, no less than M/V Tustumena
- Load vehicles and passengers:
 - at existing (as of 12/16/91) facilities of above defined ports,
 - in a time span no greater than summer 1992 schedule,
 - in all tidal conditions, except possible limitations in Homer
- Active motion control system

MISSION REQUIREMENTS CONTINUED

South East Mainline System - Requirements

Lakes, Bays, and Sounds rated
Dock, unassisted, at:

Bellingham,
Prince Rupert,
Ketchikan,
Hollis,
Wrangell,
Petersburg,
Sitka,
Juneau,
Haines,
Skagway, in the following conditions:

all tidal ranges,
all current ranges,
winds steady at 35 to 40 knots, gusting to 50,
all visibility conditions,

Transit Wrangell narrows (at water greater than +3.0 ft. MLL) and Sergius narrows
Speed adequate to make schedule, no less than M/V Taku

Load vehicles and passengers:

at existing (as of 12/16/91) facilities of above defined ports,
in a time span no greater than that shown on summer 1992 schedule,
in all tidal conditions,

Emergency Response Requirements

Provide hazardous material response to any ice free port in Alaska
Provide housing and amenities for response personnel
Provide communications/vessel traffic platform
Provide ample enclosed work space
Provide limited medical facility
Load and unload ro/ro cargo from undeveloped docks
Provide support base for smaller vessels
Be well maintained and ready to respond

DESIGN AND CONSTRUCTION SCHEDULE

The following design and construction time line describes the required events, and when they must occur, to obligate FY 1993 Federal Highway Funds.

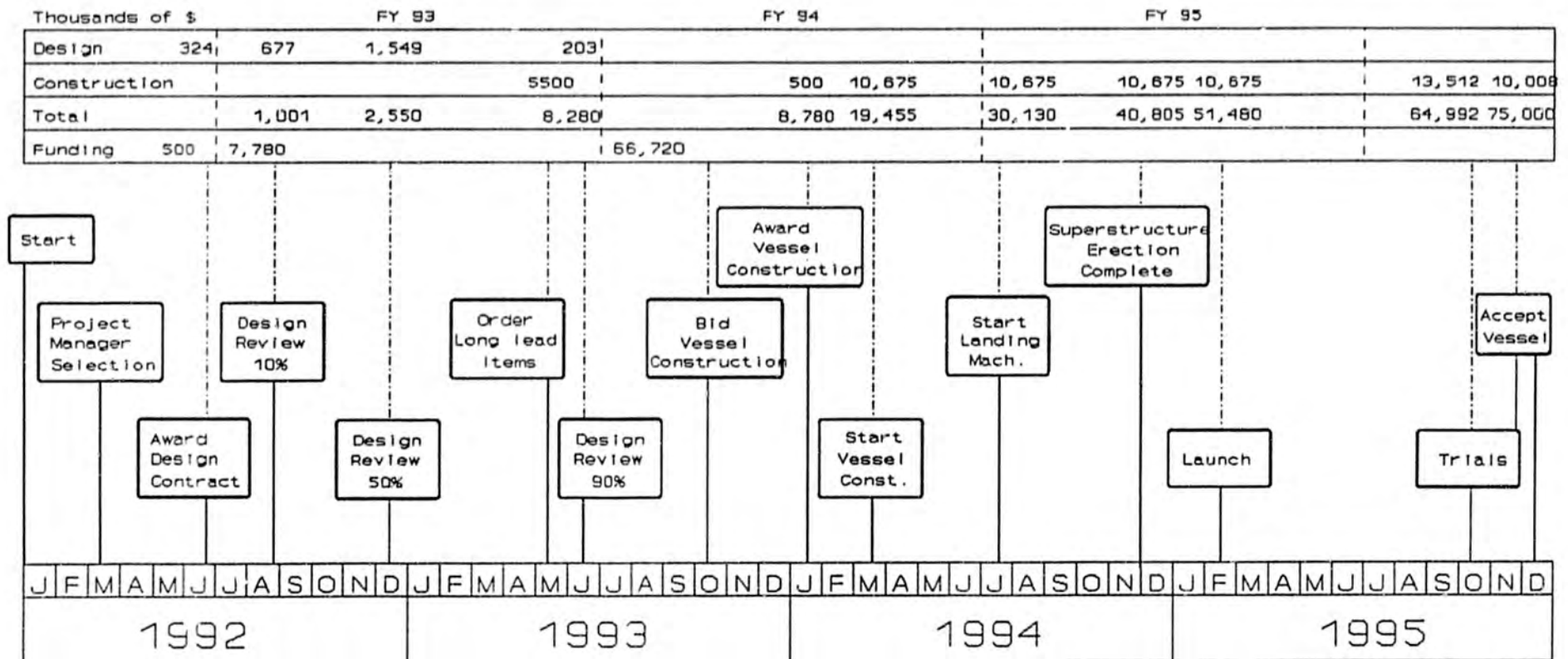


Figure 2 - Design and Construction Time Line

STEP ONE - INITIAL DESIGN PARAMETERS

VESSEL PARTICULAR:	ESTIMATED VALUE:	FINAL DETERMINATION BY:
Classification:		
	ABS +A1	Determined by owner insurance/maintenance requirements
	U.S.C.G., Oceans	Determined by U.S. Flag requirements
Dimensions:		
Length BP	340 to 380 ft	Min. by sea keeping, Max. by port restrictions and cost
Beam	65 to 74 ft	Min. by intact stability, Max by hull form and cost
Depth	19 to 24 ft	Min by strength & regulatory, Max by Damage stability & weight
Draft	15 to 20 ft	Min by hydrostatic, Max by waterway restrictions
Tonnage:		
Gross tonnage	2800 to 3900 tons	By international convention, total of inside space, less deductions
Passengers:		
Passengers	350 to 500	By vessel size, and quantity of lifesaving appliances
2 person Staterooms	40 to 65	By vessel size, arrangement, load character
4 person Staterooms	25 to 40	By vessel size, arrangement, load character
Vehicles:		
Max lane length	1500 to 2100 ft	By final vessel size, lane width, island width, clear height
Crew:		
1 person Berth	8 to 12	By regulatory requirement, and vessel functions
2 person Berth	16 to 24	By regulatory requirement, and vessel functions
Machinery:		
Main Engines	7000 to 9000 HP	By necessary speed requirement, propulsive efficiency
Electrical	1200 to 1700 KW	By size of hotel load
Propeller (C.P.)	1 to 3	By maneuvering and safety considerations
Bowthruster	1 to 2	By maneuvering, environmental considerations
Stern thruster	0 to 1	By severe maneuvering vs environmental considerations
Stabilizers	Passive or active	By seakeeping, hull form, cost
Speed:		
Service speed	15 to 20 kt	By schedule requirement

VESSEL DRAWINGS

The following drawings reflect the current designed shape and character of the new replacement vessel. At present, the design is in a very preliminary stage. *Therefore, these drawings are suitable for general discussion only.* As the design progresses, these drawings will be updated until the vessel evolves into its final form.

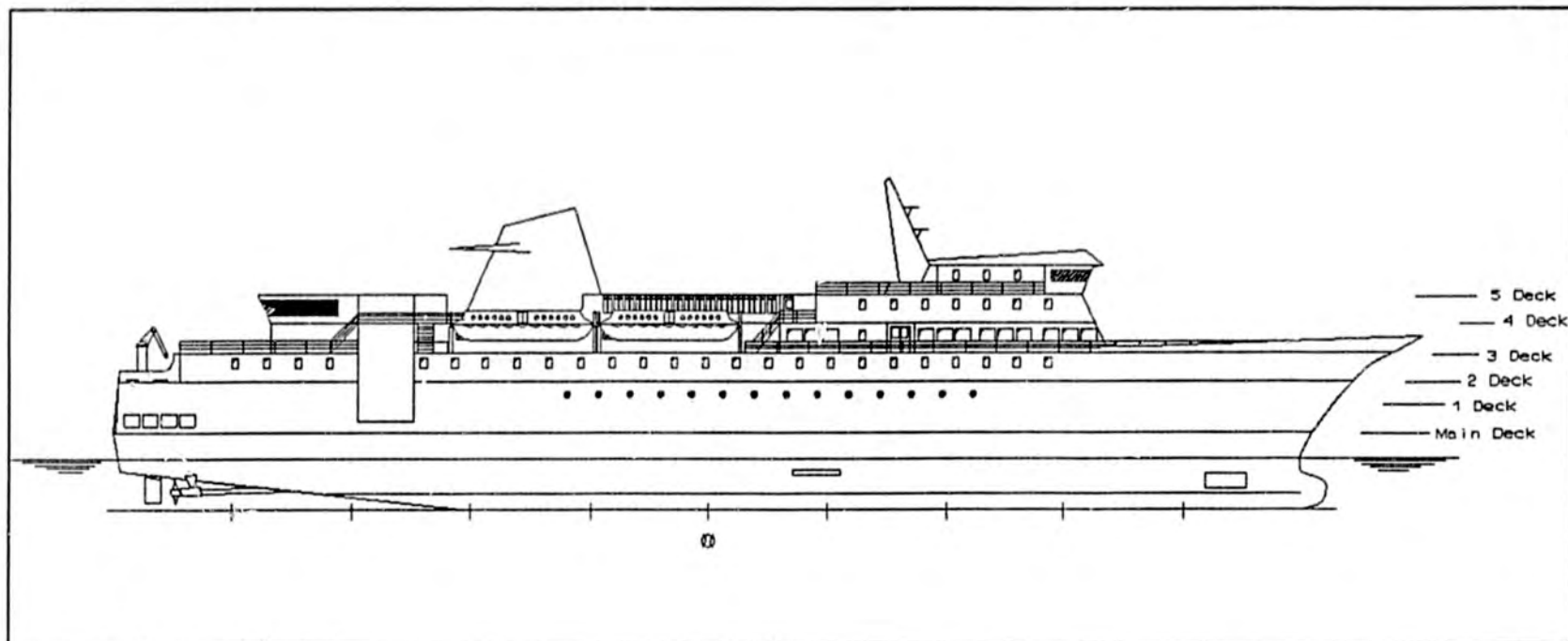


Figure 3 - Outboard Profile

VESSEL DRAWINGS CONTINUED

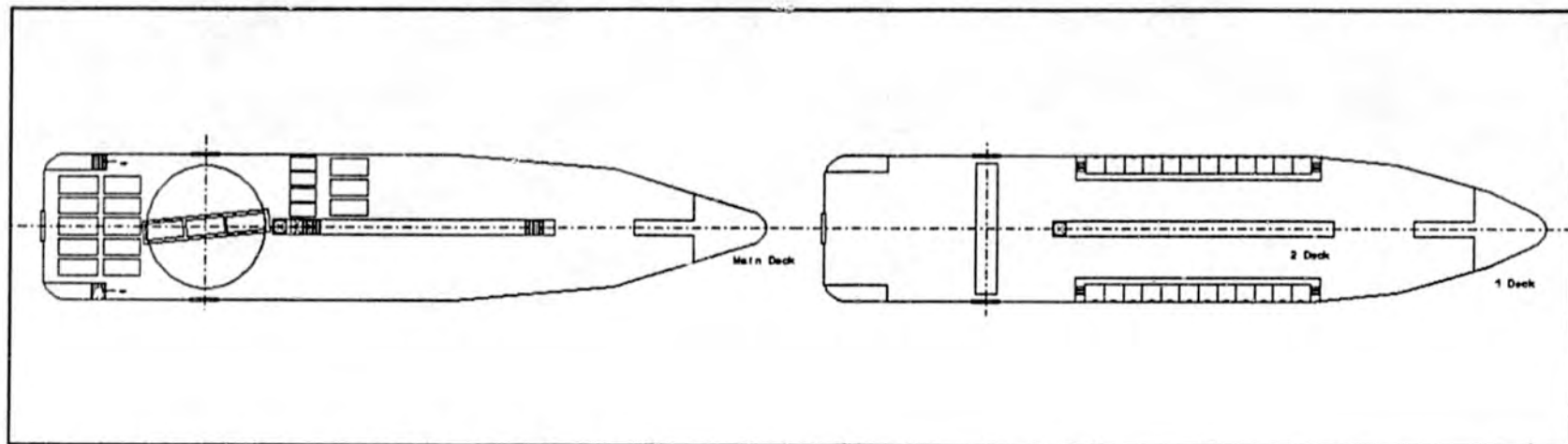


Figure 4 - General Arrangement Main Deck and 1 Deck

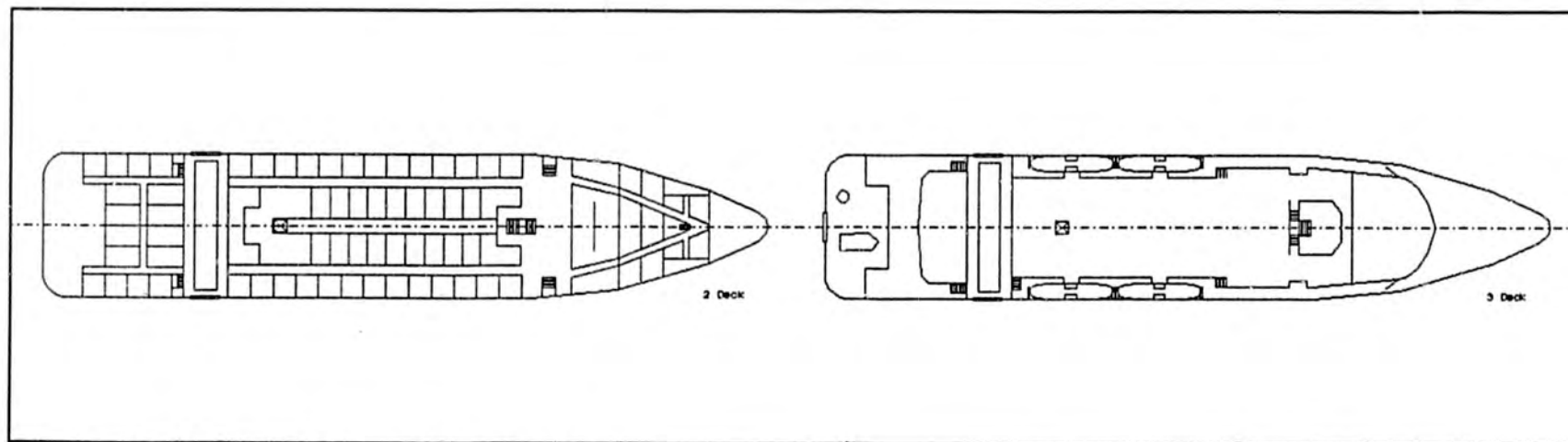


Figure 5 - General Arrangement Deck 2 and Deck 3

VESSEL DRAWINGS CONTINUED

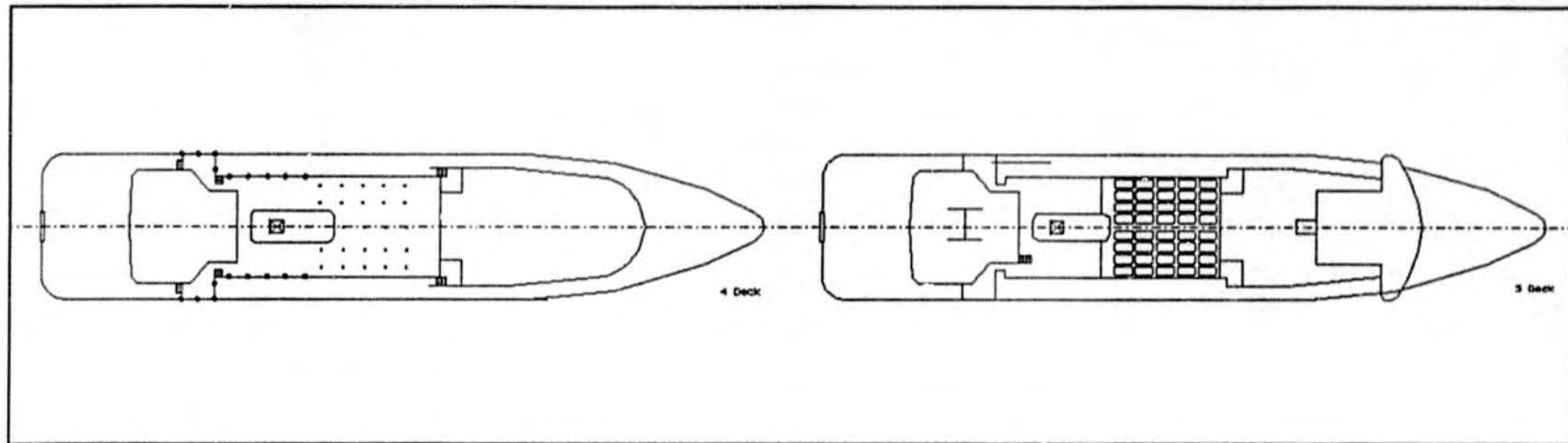


Figure 6 - General Arrangement Deck 4 and Deck 5

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ARCO Alaska, Inc.
Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 265 6468



John C. Roots
Vice President

January 6, 1992

Senator Sam Cotten
Room 11, Capitol
P.O. Box V
Juneau, Alaska 99811

Senator Lloyd Jones
Room 30, Capitol
P.O. Box V
Juneau, Alaska 99811

Dear Sam and Lloyd:

Following our recent conversations, I would like to suggest that ARCO Alaska's Senior Vice President for Exploration, Jim Davis, provide an informal briefing to the Senate Oil and Gas Committee and Senate Resources Committee on Tuesday, February 4, 1992. I suggest 2 hours, beginning at 9:00 a.m., if this is convenient. Jim's brief will focus on significant oil and gas issues including current exploration programs and recent discoveries in the Cook Inlet area. I am contacting the House Oil and Gas and House Resources Committee Chairmen to offer a similar briefing the afternoon of February 4.

Sincerely,

Vice President
Political Affairs

sb

*Stacy
barnet*

Jim Davis
February 4, 1992
Address to Legislators

I very much appreciate the opportunity to talk to you today about the petroleum industry and the outlook for its future in Alaska.

As you may know, the suggestion for this informal briefing came from casual discussions last fall with several of the committee chairmen and ARCO Alaska's senior staff. It was suggested that the key House and Senate committees would benefit from an ARCO overview of the current state of the oil and gas industry in Alaska.

Given the sharp decline in the price of crude oil since those fall discussions, and its direct negative impact on the FY92 budget and the FY93 revenue projections, it seems particularly appropriate that we offer our thoughts to you today.

In particular I am going to concentrate on exploration, for it is the cornerstone and future of the industry. To state the obvious --you can't produce what you don't find. My job for ARCO is to find it.

I will offer you some reasons why a number of companies are abandoning Alaska exploration efforts--and why ARCO, the state's most active explorer, is continuing with its high level of effort. And I will suggest what the state can do to encourage other companies to invest in exploration in Alaska.

In view of the fact that more than 85 percent of the state's income comes from royalties and taxes on oil production, it is disturbing to see that the Alaskan rig count ended 1991 at its lowest level in 17 years. There is not much promise of improvement for 1992.

If the oil industry is to remain healthy in the long term, we must continue to explore for new sources of oil and we must be successful. We must efficiently maximize production from existing fields, and in the face of lower oil prices and tougher competition, we must cut the cost of doing business.

ARCO Alaska is doing all of these things.

In terms of exploration, ARCO plans to spend \$600 million in exploration in Alaska over the next five years. In 1992, we expect to see between 15 and 25 exploration wells drilled in Alaska, and ARCO will participate in 75 to 80 percent of those wells.

In Cook Inlet, there is cause to celebrate the discovery of oil at the Sunfish prospect. A jackup rig is overwintering at Nikiski to drill a followup well next summer, to further evaluate the discovery.

This winter, ARCO has five drilling rigs at work on exploration prospects-- the most activity of any company in Alaska. This includes the BLT well north of Anchorage, where we are looking for gas. This is a unique area in that the mineral ownership includes some private land. We have paid over \$400,000 to individuals for those rights. The state has also realized over \$2 million in lease bonuses. And the local economy benefits from 37 local people who are employed at the rig site, and more than \$1.5 million spent locally for services and supplies.

ARCO also is drilling the Cabot prospect in federal OCS waters offshore Barrow, which is the third Western Beaufort Sea exploratory well. If the Cabot well is not successful, it will may be the last in the area for some time.

And we recently spudded two wells in the Colville River delta, west of Kuparuk, which will be followed by three more wells this winter.

ARCO is looking for partners to explore the Kuvlum/Maktar prospect in the Eastern Beaufort. This prospect is important in proving up enough reserves in the area to justify shared production facilities and a pipeline to the trans Alaska pipeline. Unfortunately, several companies who had planned to participate have pulled out, and if that well isn't drilled this year, I fear it won't be drilled before leases expire. That could mean the end of activity in the Eastern Beaufort for the foreseeable future.

ARCO is the only company active in the interior basins. We have an agreement with Doyon in the Kandik Basin, near the Canadian border, where we have completed extensive geological studies and seismic and other geophysical studies. We are researching new drilling systems which are less costly and have less impact on the environment. We are looking for a partner to help us drill the prospects that have been identified.

This exploratory activity is aimed at preserving ARCO's future in Alaska.

Meanwhile, in order to maximize recovery from Prudhoe Bay, ARCO and its partners are making major investments, totaling more than \$2 billion, in gas handling facilities to make it possible to recover more oil from the reservoir.

When the field went on production in 1977, we expected ultimate recovery to be 9.6 billion barrels of oil. Today, we expect to recover more than 12 billion barrels. This increase didn't just happen. It is the result of aggressive investments in wells and facilities, technological advances, and the considerable efforts of a lot of people.

And we are cutting costs. Recently, we took the very painful step of cutting some 250 of our 2,900 Alaska employees. In addition, ARCO and BP are streamlining operations at Prudhoe Bay through consolidation and sharing of services. That meant the loss of 100 jobs, many of them contract employees.

Other oil companies, including many who do not have current production in Alaska, have announced in recent months they are giving up their exploration efforts in Alaska and intend to invest their exploration dollars in foreign countries.

This is disturbing news because it is in both the state's interest and ARCO's interest that Alaska maintain an aggressive exploration program, with a vigorous service industry supporting it.

You may wonder why ARCO wants competition in Alaska. First: given the high cost of exploration and the low chance of commercial success, we need partners to share the risk. Onshore, it costs from \$5 million to \$10 million to drill a single well; offshore, the cost can range from \$20 million to \$50 million or more. The only way to stay within a reasonable budget and still participate in a significant number of wells is to team up with other companies.

Second: Because of the way land is traditionally leased, in relatively small blocks, companies must form partnerships to create a leasehold large enough to justify an exploratory well. While we need such partnerships, coming to agreement on when a well will

be drilled, and how costs and production will be shared, is difficult, especially if the companies have differing views of Alaska.

Third: ARCO alone cannot support a viable service industry, to perform not only the actual exploration drilling but also to provide such services as earth moving, road building, well logging, well testing, camp building, seismic activities, and catering. As activity decreases, the cost of services increases, and so on. It's called a death spiral.

Now to a key question. Why is Alaska losing the battle for exploration capital?

To answer this question, we must understand a little about the exploration process. Exploration is a long term venture. Typically, it begins with broad regional geological studies of areas of considerable extent, involving areas of a few hundred miles square, or tens of millions of acres.

These studies reflect the fact that although the rocks have changed very little over human existence, our understanding of them is continually changing. To quote Parke Dickie, the pioneer petroleum geologist, "You can find oil in new places with old ideas, or in old places with new ideas. Seldom can you find oil in old places with old ideas. In the past, we thought we were running out of oil, but in fact we were running out of ideas." End of quote.

The next step in the exploration process is to conduct seismic and other geophysical studies over more local areas, tens of miles square, selected through geologic studies to be of the highest interest. Prospects identified then must pass rigorous economic screening before they are drilled. The economics include risk factors and costs of developing and marketing oil, if it is found.

This process takes at least five years, and must take place in advance of any lease sale. Once we are successful in acquiring leases through the competitive bid process, then the permitting process begins. An offshore well can require up to 30 permits or regulatory approvals from state, federal and local governments. Only when all approvals have been obtained can drilling begin. A delay of a few months can mean a year's delay in drilling where seasonal drilling restrictions are in effect.

The results of drilling that well, and perhaps others, are incorporated into existing geologic concepts and the process repeats itself.

If we are lucky and discover oil, another five to ten years will be needed for permits, design and construction to put the new field into production. Only then will we be in a position to begin to recoup the costs of exploration and initial development.

An example is ARCO's recent Sunfish discovery in the Cook Inlet. We began the basic studies four years ago, and developed new geologic concepts. In 1990, we tested these new geologic concepts by drilling the Sturgeon prospect at a cost of \$12 million. We didn't find oil, but it was a technical success because it confirmed these new concepts.

It encouraged us to drill the Sunfish prospect, at a cost of \$30 million. That was a successful test: We discovered oil! We are planning delineation drilling this year. If it is found to be economic, it will be five to ten years before production facilities are designed and the construction is completed.

Anything that adds uncertainty to this long-term process is undesirable because it increases the risk to the explorer and makes further exploration less desirable.

Uncertainty is one of the reasons the industry is exploring less in Alaska and the Lower 48 and is investing those dollars overseas. Just since 1985, the U. S. oil industry has increased its foreign investment from 40 percent to 80 percent of its total capital investment.

A recent Oil and Gas Investors article points out that democracies may seem inherently attractive and safe to Western eyes, yet they have a habit of making changes that affect the business community nearly as often as elections are held.

This is why the U.S. itself is increasingly regarded as being a high risk country compared to Canada, the U.K., or Indonesia, the article points out. "When viewing the spectrum of risks associated with foreign investment, the U.S. comes under a great deal of scrutiny. In terms of volatility and unpredictable tax law changes, the U.S. record is not the best." Unquote.

Uncertainty of regulation and increasing environmental costs could be added to this spectrum of risks. And exploration investments must be factored into companies' long-term planning.

Consider this analogy. Suppose you wanted to buy a lot on which to build a house five years from now. Say you had a choice between a subdivision in each of two towns. In one the town has committed to follow the building code standards that are recommended nationally and has a history of stable zoning and responsive permitting. The other has a history of imposing unique building codes, has no zoning, and is erratic in issuing building permits. Which lot would you buy? Would you even consider buying the latter lot?

The petroleum industry is faced with a similar decision. Generally speaking, an explorer overseas will know the taxation and permitting requirements prior to making any investment. In fact, foreign governments have shown willingness to be responsive to adverse conditions to accommodate marginal fields and hard economic times.

As an example: the government of Alberta has announced a royalty holiday for wells drilled in the next two years.

Companies also are not exploring in Alaska because they are being denied access to areas with oil potential, particularly federal lands onshore and offshore. Given the exploration process I have described, you can see it is impossible to know in advance precisely where your studies will lead you. Yet the federal government has withdrawn large blocks of acreage within offshore sale areas, leaving an unconnected collection of blocks. And the Coastal Plain of the Arctic National Wildlife Refuge, the most prospective onshore area in the U.S., continues to be off limits to exploration.

In the Lower 48, 40 per cent of the federal oil and gas lands on shore are now unavailable because of leasing moratoria or other restrictions. And there is a ban on offshore leasing from Maine to Florida and from Seattle to San Diego. For these reasons, the industry is not investing in pre-lease activities outside the Gulf of Mexico.

Industry has spent \$10 billion exploring the Alaskan OCS, through 1990, including 75 dry holes. More than \$6.5 billion of that went for

lease sale bonuses and rentals, while another \$3 billion went for actual drilling costs.

The majority of companies conducting Alaskan OCS exploration have had little participation in onshore drilling. Given the record of dry holes offshore, it should come as no surprise that these companies are reassessing their positions and are looking elsewhere.

Why isn't ARCO taking its exploration dollars out of the state?

Since the mid-eighties, we have had an exploration program balanced between the onshore and the offshore. With the troubles in the OCS, ARCO, unlike some of its competitors, was able to easily redirect efforts onshore.

We understand that exploration is a long term and technically based business. Over the past four years, ARCO has invested over 250 man years in basic regional studies of Alaska. This next summer marks the 37th consecutive year that ARCO has had geologic field parties. No other company matches that record. We believe these investments give us an edge over our competitors. This understanding has led us to aggressively invest in both state and federal acreage.

In addition, our people live and work in Alaska and are able to communicate routinely and in a timely way with the state agencies. But the most important reason ARCO maintains an aggressive exploration program in Alaska is that ARCO, or its predecessors, have had exploration success.

We made the discovery at Swanson River in 1957 that helped achieve statehood for Alaska. We also discovered Prudhoe Bay, Kuparuk, Lisburne, and Point McIntyre. Last fall, we announced a discovery at our Sunfish location in Cook Inlet. It was the first Cook Inlet oil discovery in 26 years.

ARCO is working hard to build a future here. Through continually evolving technology, we believe that Alaska offers a resource base that is as prospective as anywhere in the world. If we didn't, we would not be Alaska's most active explorer.

Let's look at Alaska's competitor countries overseas. Those countries offer a business environment that is compatible with the exploration process and encourages it.

They grant concessions on large contiguous blocks of acreage, from 250,000 acres to 25 million acres. Exploration rights are valid for a length of time that is appropriate to the process. Stipulations are known up front, including terms of operations, environmental requirements and development requirements. In addition, partnerships are known ahead of time as they are developed prior to joint bidding for the concessions.

Of course there are work requirements. But no company bids on these types of concessions unless they plan to conduct activities.

So what can the state do to reverse the trend to overseas investment?

For one thing, the state must be a strong advocate of a stable and truly area-wide federal OCS lease sale program in Alaska. And the state should also support the opening of the ANWR Coastal Plain--not only for the windfall from bonuses it would receive, but because a discovery in ANWR could justify the construction of a pipeline to connect with the Trans Alaska Pipeline. Discoveries already made in the adjacent area appear to be too small to justify the costs of development. They most likely will not be developed unless additional reserves are found.

The state also must do more to entice explorers back onshore. While the state has done a good job in allowing access to state lands, and has provided reasonable stability in administrative processes, there is room for improvement.

We see a continual escalation of permitting requirements. Each additional permit is more stringent in its stipulations. The value of this escalation is doubtful, both from an environmental perspective and certainly from a cost/benefit viewpoint. As an example, it recently took three years to permit a new drill pad within the existing Kuparuk Field.

There is also opportunity to streamline the permitting process. More than time is lost in the maze of paperwork. ARCO employs 35 people full time, and others spend part of their time, to handle the permits

required to drill about a dozen exploratory wells each year, as well as for development projects in existing fields. If some of those people could be redirected to identifying exploration prospects, we could have a much better chance of finding the reserves both Alaska and ARCO need.

Another way the state could help is in encouraging the formation of exploration units. The exploration unit concept is a powerful way for the state to level the playing field in competition with other countries. It allows the combining of tracts with different expiration dates and different owners into a unit which is held together beyond individual lease expiration dates, as long as specified work is done.

We see the current process of forming units becoming more burdensome. What should take a week for administrative review by the state is now taking six months. The Legislature should let it be known that it supports this powerful concept and encourages the use of exploration units.

We are happy to hear that the state is considering the concession arrangement that is attracting capital overseas. The state and native corporations must work together, especially in the interior basins, to offer large blocks of land for exploration. It is an idea that could be used elsewhere in the state, in areas not adjacent to current production.

The completion of the state's land selections, which the Department of Natural Resources has identified as a top priority, offers a unique opportunity to aid the exploration process. Lands can be selected to preserve access to prospective oil and gas resources and for transportation corridors for pipelines, if exploration is successful.

It would be difficult to restore Alaska to previous high levels of exploration activity. But with the improvements I have suggested, I believe that the state can at least stem the tide of retreating exploration dollars and perhaps bring new life to Alaskan exploration.

I hope that this perspective is of help to you and I wish you all the best for this session. Thank you for your time and attention.



BP EXPLORATION

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

March 24, 1992

Dear Legislator:

Attached, please find the Presentation "Alaska and BP - A Shared Future", given by Mr. Brian Davies before the House Special Oil and Gas Committee on Friday, March 20, 1992.

Sincerely,

A handwritten signature in cursive script, appearing to read "John".

John Ringstad
Associate Director,
Government and Public Affairs

ALASKA AND BP - A SHARED FUTURE

Testimony of BP Exploration (Alaska) Inc. to the House Special Oil & Gas Committee

By Brian E. Davies
Vice President

March 20, 1992

Mr. Chairman, Members of the Committee. Good afternoon. My name is Brian Davies and I am Vice President for Endicott and Development Projects for BP Exploration (Alaska) Inc. My testimony today will share with you some thoughts about the outlook for Alaska as BP sees it, and our plans to remain a major player in Alaska.

In the process, I hope to debunk thoroughly a number of rumors about BP that have persisted for some time -- rumors, for example, that we are turning over our operatorship at Prudhoe Bay to ARCO, that BP is shifting emphasis from Alaska to new areas overseas such as Colombia, even that BP is leaving Alaska and has quietly put its Alaskan assets up for sale. None of these rumors is true. Indeed, they could hardly be more mistaken about our intentions. As you will see, the strongest and best demonstrations of BP's continuing Alaskan commitment have been misconstrued as evidence of an intent to abandon this state.

Let me begin by reminding everyone that BP has been and remains the largest investor in Alaska by far. We own, and have paid for, just over half of the investment in the main oil reservoir at Prudhoe Bay -- which is not only the largest oil field in North America, but also required the greatest investment to develop. We own, and have paid for, more than half of the investment in Endicott. We own, and have paid for, half of the investment in the Trans Alaska Pipeline System. We own, and have paid for, approximately 40% of the investment in the Kuparuk River field, currently the second largest oil producer in the United States. We have assembled the greatest fleet of Jones Act ships in history to transport our Alaskan oil. But unlike our partners on the North Slope, we are barred by the Jones Act from owning any of these ships.

Here is a table showing how much money BP has spent for Alaskan projects during the last decade.

<u>Year</u>	<u>BP's Alaskan Spending</u>	<u>Alaska Royalty and Taxes Paid</u>
1982	3.1	1.7
1983	1.9	1.4
1984	1.9	1.5
1985	1.8	1.6
1986	1.5	0.7
1987	1.1	1.1
1988	1.1	0.9
1989	1.4	1.1
1990	1.5	1.8
1991	<u>1.5</u>	<u>1.2</u>
Total	16.8	13.0

Figure 1. BP's Historic Spending on Alaskan Projects (\$ billions)

As you see, in the past ten years BP **alone** has spent some \$16.8 billion -- an average of nearly one and a half billion dollars a year. These expenditures have enabled BP to become and remain the largest producer of oil in Alaska. They have also made us the State's largest taxpayer -- a distinction we did not actively seek, but one which we acknowledge and accept. The table shows that we have paid some \$13 billion in Alaskan taxes and royalties since 1982.

Today our commitment to Alaska remains as strong as ever. This year BP again plans to spend on the order of one and a half billion dollars in developing and operating our Alaskan assets. To those who fear BP may forsake Alaska in favor of Colombia, let me put this into perspective: Our planned spending on Alaska is over **seven times** what we plan to spend on Colombia this year. And we have committed ourselves to the GHX2 gas handling project for Prudhoe Bay -- a one and a half billion dollar investment, of which we are paying half. Clearly we would not continue investing heavily in Alaska if it were not important to us. The sheer size of our ongoing investment is proof of just **how** important it is.

Well, so much for the past and the present. What about the future? How does Alaska figure in BP's longer term plans?

The short answer is, Alaska figures very large indeed.

As some of you may already know, for several years BP has been actively divesting a number of its oil and gas interests that do not fit within our strategic, long-range plans. Our purpose is to focus on those assets that are truly "core" assets for our future business. We have, for example, sold our interests in onshore properties in the Lower 48 principally because they were too small and too numerous and tended to distract us from effectively managing our major properties. BP's Alaskan interests are definitely part of our "core" both because of their present size and because of their potential for the future.

Let me briefly explain why Alaska is part of BP's "core" portfolio. For those of us in the "upstream," or exploration and production side of BP's business, the challenge is not only to produce the reserves we already have, but we must also look continually to find new reserves to replace what we are producing.

To clarify my point I will use the term "**resource**" to mean the total amount of oil or gas that is in place, without regard to how much of it might ever be recovered. In contrast, I will use the term "**reserves**" to mean that portion of the resource in place which we believe can ultimately be produced using existing technology and under reasonable economic conditions.

In the case of Prudhoe Bay, for example, the amount of oil originally in place in the ground was some 22 billion barrels. Of this, some 9.6 billion barrels were seen as being recoverable when the field began producing. In other words, the oil **resource** was 22 billion barrels and the **reserves** in 1977 were 9.6 billion barrels. Since then some 8 billion barrels of oil have been produced, leaving a remaining **resource** of 14 billion barrels -- 22 billion originally in place minus the 8 billion that have come out. Similarly, the remaining **reserves** of the field would be 1.6 billion - 9.6 billion minus the 8 billion already produced.

But the remaining reserves at Prudhoe Bay are much greater than 1.6 billion barrels. What has happened is, we and our partners in the Prudhoe Bay field have been able to convert more of the **resource** into **reserves**. Instead of 9.6 billion barrels of recovery, we have managed and developed the reservoir in such a way that we now see technologically feasible ways of recovering 12 billion barrels or more, assuming economic conditions remain reasonable. In other words, some 2.4 billion barrels of oil have been converted from mere **resource** into **reserves** since 1977. And consequently the remaining reserves are not 1.6 billion barrels, but a whopping 4 billion barrels -- which still makes Prudhoe Bay the largest oil field in the United States even after 15 years of production.

Here is a table that summarizes the arithmetic I have just gone through.

	Resource	Reserves
Estimated as of 1977	22	9.6
Additional Reserves from Resource		<u>2.4</u>
		12.0
1977-91 Production	<u>8</u>	<u>8.0</u>
Remaining as of 1992	14	4.0

Figure 2. Oil Resource and Reserves of Prudhoe Bay

In terms of recoverable **reserves**, the additions to Prudhoe Bay since 1977 are greater than the total oil reserves for Kuparuk, and more than twice as great as the oil reserves of Endicott, Lisburne, Point McIntyre, Niakuk and Milne Point combined. In fact, nowhere else in the world during the past decade has BP been more successful in adding **reserves** of oil to its inventory than on the North Slope.

So now you know where one of BP's major focuses has been in terms of looking for new **reserves**. We have been looking right in our own back yard -- at

the substantial **resources** that have already been discovered -- to try to figure out how we convert even more of the **resource** into recoverable **reserves**. And we will continue these conversion efforts. After all, even with 12 billion barrels of **reserves**, there are still some 10 billion barrels of **resource** there for us to work on. This is why BP views Alaska as part of the "core" for its future business.

Besides exploring for ways to convert **resources** into **reserves**, BP is actively doing conventional exploration work on the Slope as well.

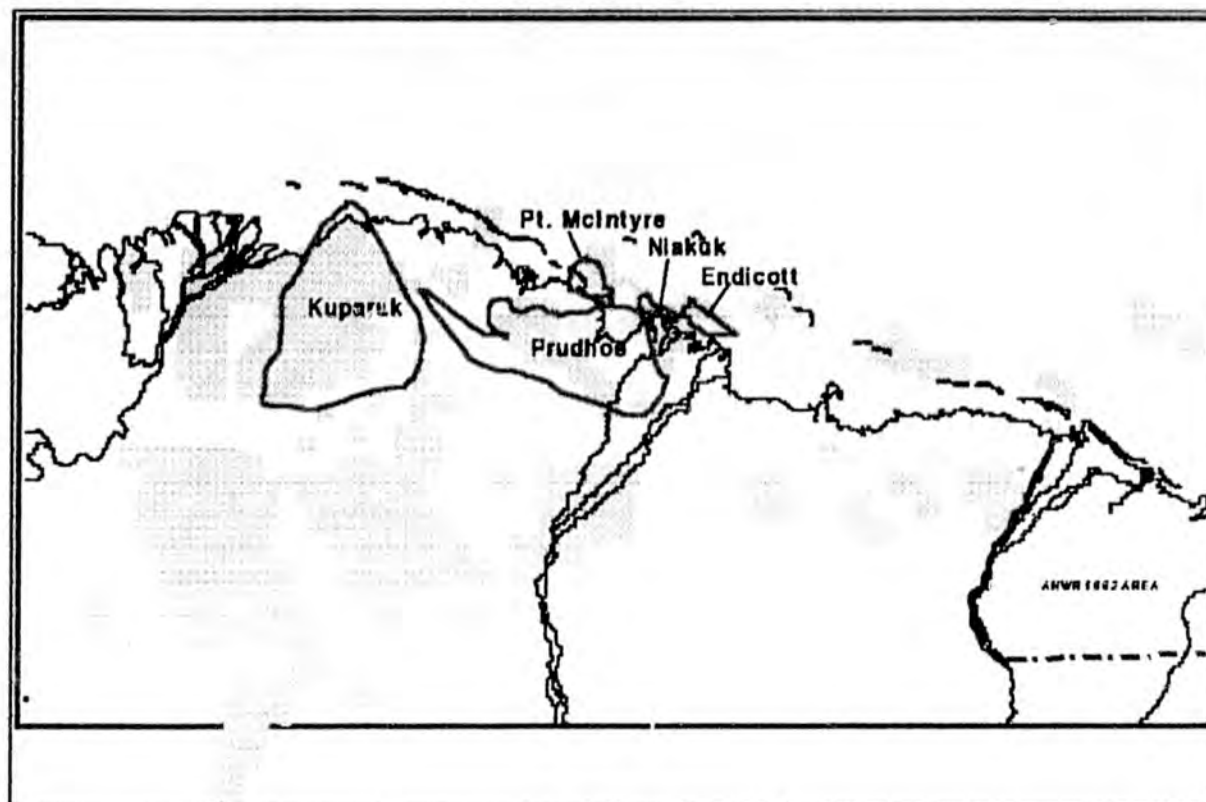


Figure 3. Map of BP's North Slope Leases

Here is a map showing acreage on the North Slope in which BP owns a leasehold interest. Note the land outside the producing limits of the fields currently in production. As you can see, BP's position onshore in the Central North Slope is a dominant one.

Why are we focused there? We are, quite simply, looking for oil that is close to TAPS. Any oil we find there should not only cost less to move to the pipeline, but its nearness to the pipeline should also allow it to come into production much sooner than if it were farther away. In addition, we are looking for oil in and around the edges of the already developed fields. As production from the fields declines, there will be unused capacity in their facilities that could be used for any new oil we may find. Using existing production facilities instead of designing and installing brand new facilities will reduce the costs of producing the new oil, and thus will lower the size of discovery that has to be made in order to be economic.

You may have heard that BP recently decided not to participate in the Kuvlum well in deeper water of the Beaufort Sea, and people in some quarters have taken this as a sign of BP's lack of commitment to Alaska. But let me say here and on the record that BP withdrew from Kuvlum because it does not fit with our strategy and position on the North Slope. As you can see from where we own leases, our focus is overwhelmingly onshore and in shallow waters fairly close to shore. With Endicott we have become the technological leader for small-footprint developments onshore or on an island in shallow waters.

But Kuvlum would be something very different. Even if a major oil discovery were made, Kuvlum is far enough offshore that its development would require solutions to such major problems as moving pack ice, installing production facilities in such seas in more than 100 feet of water, and developing a way to bring the production to shore. We considered becoming the pioneer in advancing the technology that would be needed to overcome these problems, and we found that we would have little further use for the new expertise and knowledge we would gain. We simply don't have other acreage where we could apply that technology. So we decided to let those explore and develop Kuvlum for whom it will be a better fit.

Meanwhile, we will continue to explore those prospects that do fit with our position and strategy. This year alone we plan exploration efforts on our acreage at a likely cost of more than \$20 million. The two or three exploratory wells we plan for this year are right in line with the historic rate of exploratory wells in which we participated during the past decade, which averaged 2.4 wells per year.

I would like to talk now about the decline in Prudhoe Bay production, for it is forcing us to take various measures that have led to the greatest misunderstanding about our long term intentions for Alaska.

Prudhoe Bay is in decline. It has been since 1988. More important, it will continue to decline, significantly, over the coming years. And as production declines, so do revenues -- both our revenues and the State's.

Julian Darley, President of BP Exploration (Alaska), described the "new economic order" on the North Slope very clearly last January during an address at the "Meet Alaska '92" forum put on by The Support Industry Alliance.

Here is a simplified illustration of the production and revenues from Prudhoe Bay.

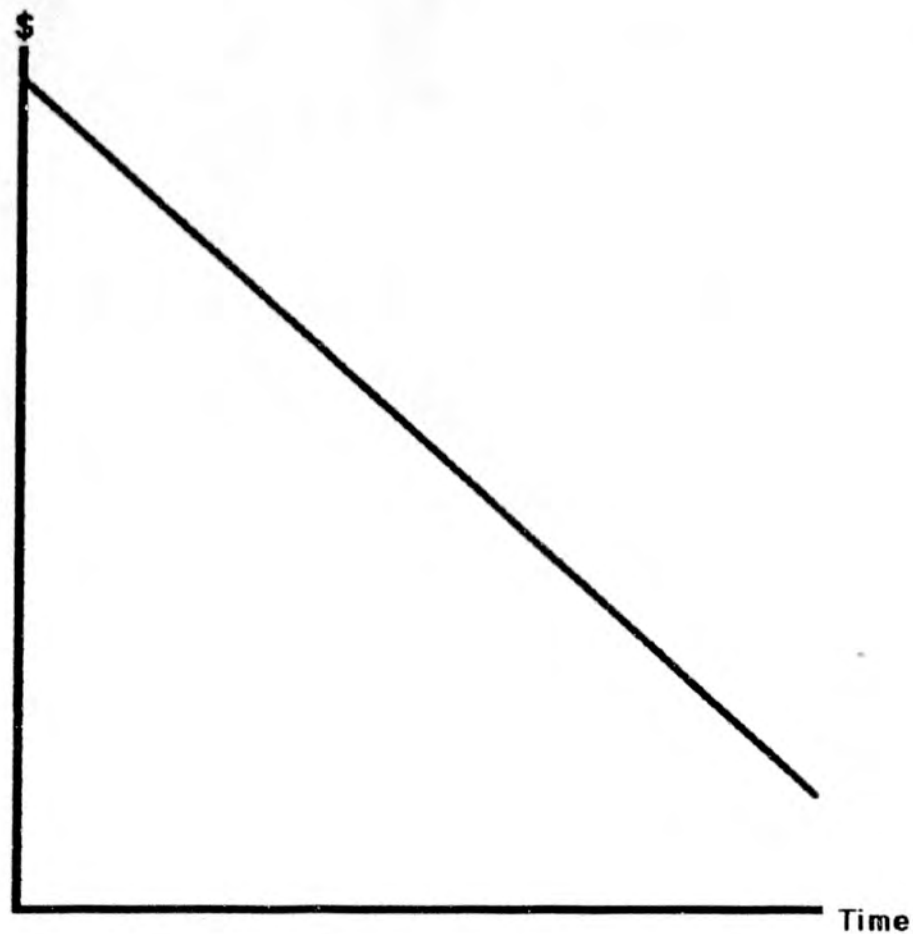


Figure 4. Illustration of Oil Production Decline

This illustrates the fact that oil production is in decline. This is the part of the picture the State sees, since state royalty and production tax revenues depend on the price of oil and the volume being produced.

But there is another side of the economic picture that we, as a working interest owner in the fields, are seeing. This is the cost side of the ledger.

Here is a simplified illustration of the costs of operating the field, based on historic experience.

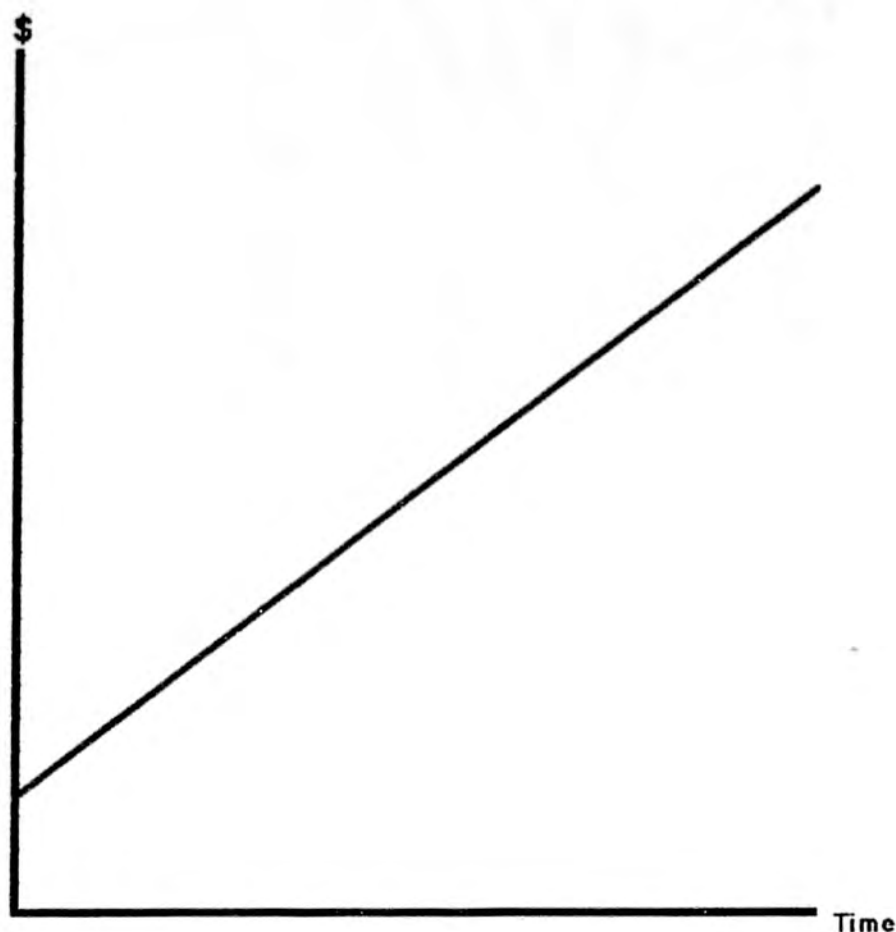


Figure 5. Illustration of Increasing Operating Costs

As this illustration suggests, costs have been rising. And we expect them to continue to rise because the industrial challenge is increasing. Although less oil is being produced, more and more gas and water have to be handled in operating the field.

This side of the economic picture is largely invisible to the State -- particularly in terms of its petroleum revenue -- because the production tax and royalty revenues are based on the so-called "wellhead value" of the oil and are not affected by the costs of producing that oil.

Now here is an illustration of what the complete economic picture looks like when you put the production and the cost trends together.

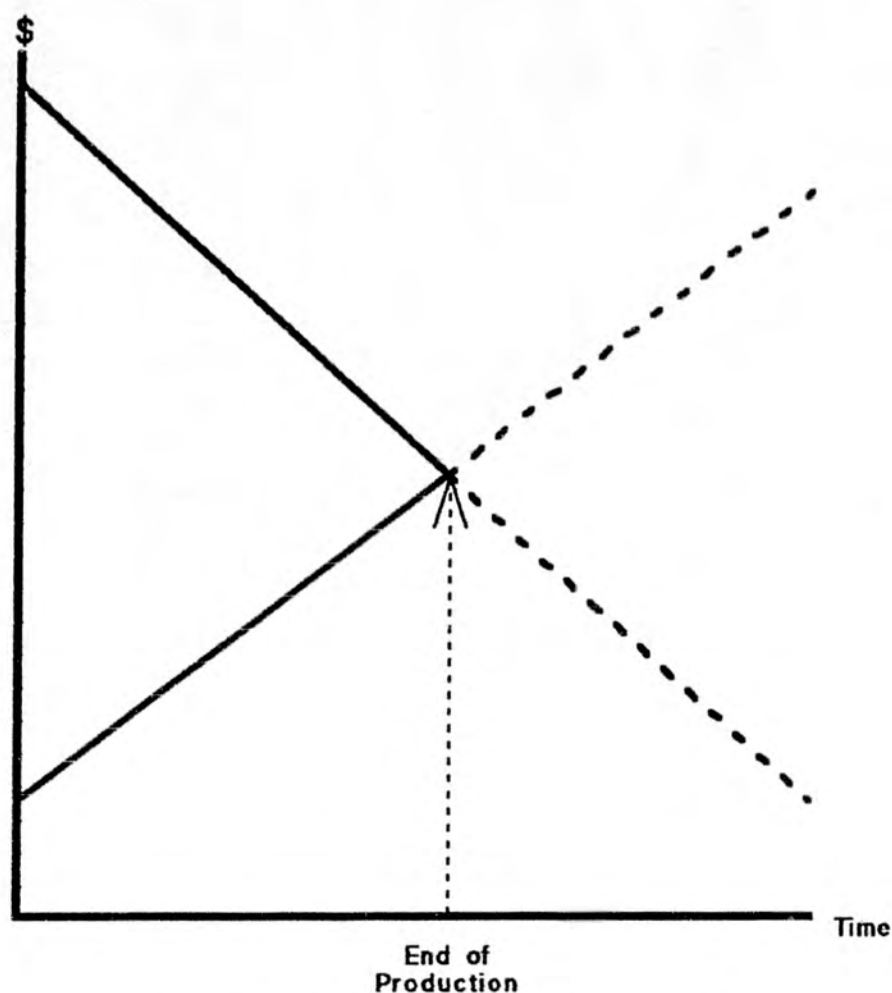


Figure 6. Effect of Rising Costs and Declining Production

Yes, that's right, production stops and the field dies. When the operating costs of production overtake the revenues from that production, it makes no sense to continue operating the field. So it gets shut down. This is what happened with the two platforms in Cook Inlet that have been shut down in the past year. Eventually this is the ultimate destiny of every oil field — or of any mine or other activity that draws against a depleting, finite resource.

With this prospect staring us in the face at Prudhoe Bay, what can be done about it? One potential solution would be to reverse the downward trend in revenues, as the next slide illustrates.

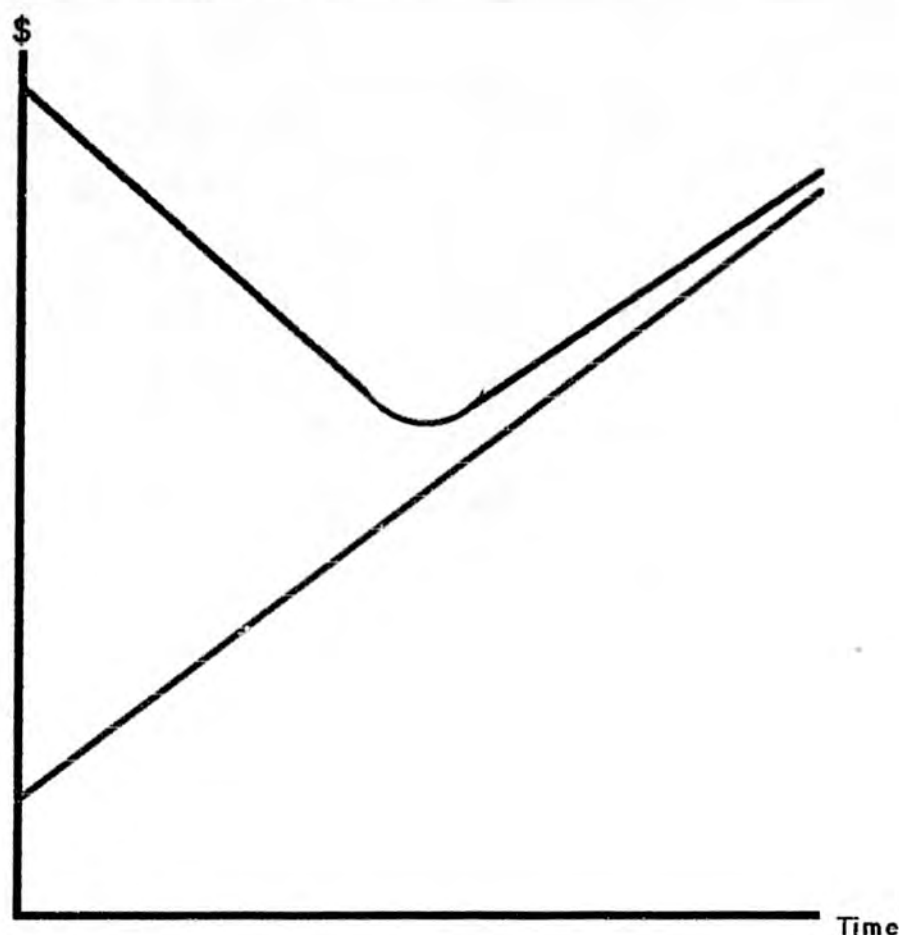


Figure 7. Effect of Reversing the Revenue Decline

But is this solution realistic? What would have to be done to make it come true?

To increase the revenues, there must be either an increase in prices or an increase in production, or an increase in both. There is, of course, one small practical problem with repeatedly raising oil prices enough to put revenues back on an increasing path and keeping them there. That problem is the market. Oil producers have to take the price the market offers, and cannot dictate prices to the market. In the early '80s even OPEC discovered that it could not ignore the laws of the market and raise oil prices indefinitely. Following the massive price increases of the 1970s, oil consumption dropped, and at the same time new supplies of oil were becoming available because OPEC's high prices had made them economic for the first time. In the end these market forces meant that OPEC members could not sell as much oil as they wanted to, and the effectiveness of the cartel finally collapsed in 1986 as the result of competition among its members.

What about increasing revenues by increasing production? Well, almost by definition, the fact that Prudhoe Bay is in decline means that production cannot be

increased. Instead it steadily decreases. But this does not mean there is nothing to be done on the production side of the equation.

For, in fact, we can do things about the **rate** of decline. Even though we can not reverse the decline in production, we can slow it down. And this is what we have been doing. For example, last year's program of well fracking, workovers and other activities to stimulate production from existing wells succeeded in slowing the rate of decline by an average of 126,000 barrels a day from what it otherwise would have been. In addition, because the GHX1 gas handling expansion project was on line during the entire year, total production of hydrocarbon liquids from Prudhoe Bay in 1991 stayed almost exactly even with 1990.

This temporary arrest of the decline in production during 1991 was a tremendous achievement, if we may say so ourselves. But it did not come cheaply. We and the other Prudhoe Bay owners spent over \$225 million in 1991 doing frac work and well workovers. The GHX1 project cost \$400 million. The point is this -- **slowing down the production decline requires a lot of new investment.**

While it costs a lot to slow down the decline, BP believes there are numerous new investment opportunities that will prove worthwhile. Here is a graph illustrating how the decline in North Slope production can be slowed down by new capital investments.

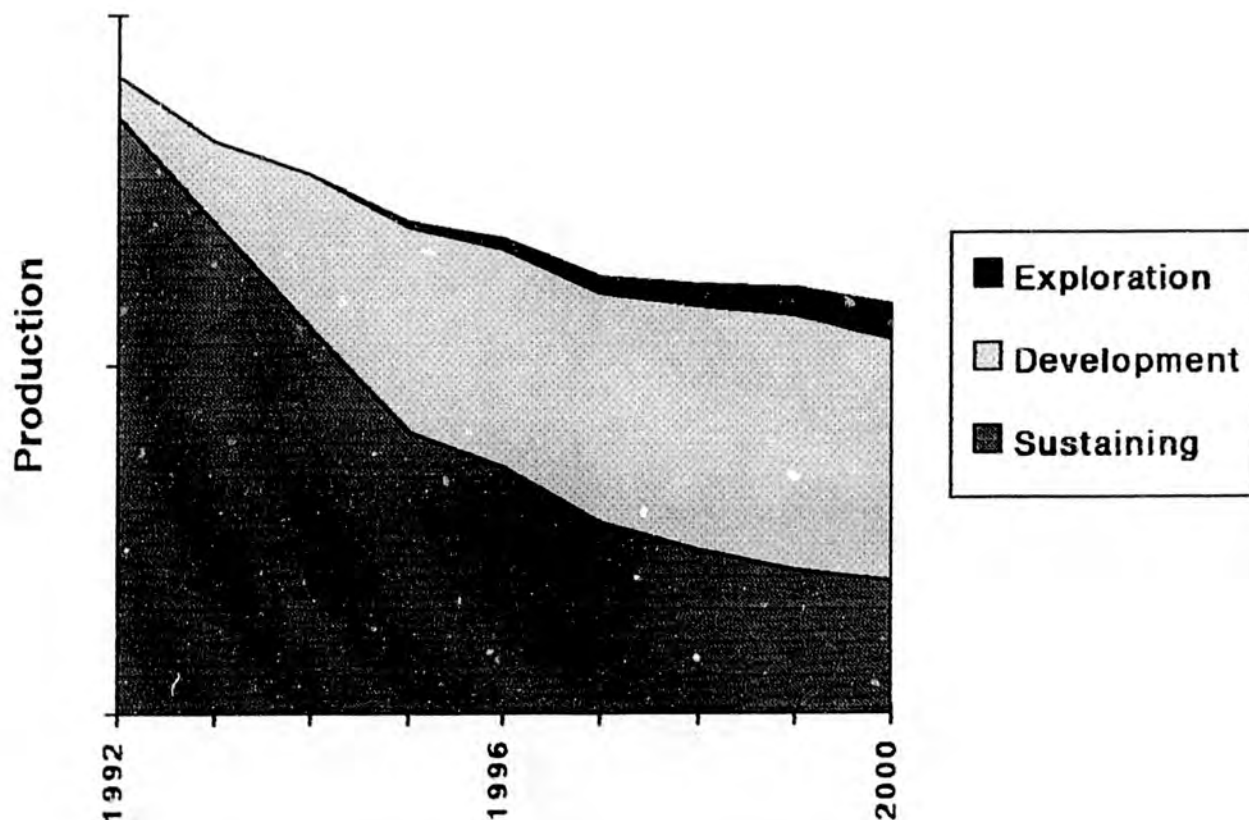


Figure 8. Production Potential from New Investments

The bottom area of the graph represents our production that would come from the existing investments in North Slope fields. We call it the "sustaining" production. It's basically what production would be if for some reason there were no further investments to develop the fields. As you can see, the production drops quite rapidly -- especially in the next few years -- and then it flattens out a bit toward the end of the 1990s although it is still always declining.

The significant layer of production lying immediately above the sustaining production is the additional production that we would get from continuing to make investments to develop the known fields on the Slope. These include drilling more wells at Prudhoe Bay, Lisburne, Endicott and Kuparuk; expanding the enhanced oil recovery, or EOR, operations at Prudhoe Bay and Kuparuk; extending the area of the Prudhoe Bay waterflood project; and developing Point McIntyre and Niakuk. As you can see, the production benefits of continuing these activities are substantial and will grow during the decade. The widening in this layer that you see starting in 1995 reflects the start up of the GHX2 gas handling project for Prudhoe Bay.

But the cost of these potential new investments is tremendous, and our share could total more than \$3 billion over the rest of this decade. This would be over and above the more than \$10 billion we will be paying in operating costs during the same time.

Finally, at the top of the graph you see a comparatively thin, but steadily widening layer of production beginning in the mid-1990s. This represents an estimate of the additional production we would hope to get from reservoirs yet to be discovered on the Slope. It represents the initial payoff for our exploration efforts. Comparing this layer to the other layers of production above the sustaining level, you can see once again why BP focuses its efforts so much on wringing every possible barrel out of the known **resources**, converting them into **reserves**.

But as you can also see, a substantial portion of the remaining **reserves** will only be produced as the result of substantial new investments. These new investments must stand or fall on their own economic merits. To make no bones about it, BP is a profit-seeking enterprise for our shareholders. We will make these new investments if they are sufficiently attractive.

Here is where Alaska can make a crucial contribution to help us justify making these new investments -- **it can maintain stability in its tax structure**. We did not like the change to the ELF formula in 1989. Not only was the change unnecessary, but the new formula was designed to penalize Prudhoe Bay and Kuparuk. And it does. Still, even under the new formula, we can evaluate the attractiveness of our new investment opportunities. But changing the rules of the game again, particularly if they target Prudhoe Bay and Kuparuk, will destabilize the tax structure and prejudice the major new investments and the resulting production that I have just discussed.

I'm not sure whether you have all had a chance to read the letter to the Finance Committee by David Pritchard of BP, raising a warning flag about the nickel-a-barrel oil tax surcharge. In case you haven't, I am attaching a copy of it to

my written statement to the Committee. I will not repeat his points now, but I urge you to consider his letter carefully.

Stability means more than not changing the tax laws. Since 1977 virtually every aspect of North Slope production and transportation operations which adversely impacted the state's revenue picture has been in litigation. Taxes, royalty and pipeline tariffs. While those of us based in Alaska understand that differences will exist between the State and the producers, this litigation always has high visibility in the board rooms of the producers. Alaska, when compared to other jurisdictions, is much more litigious -- a fact acknowledged two years ago by the Legislature's own international oil consultants. I am suggesting that at this stage of development on the North Slope we must find more rapid and economical ways to resolve our differences. Recently the State and the pipeline companies had a successful experience in alternate dispute resolution in the pipeline corrosion case, and we feel similar alternatives to litigation should be utilized for other disputes in the future.

Specifically with regard to tax administration, it is our experience that the rules of the game have been repeatedly changed as new "interpretations" are applied retroactively years after the fact. These new positions are very different from what was intended when the tax statutes and regulations were written. You would expect that it should at least be possible for us to pay the correct amount of royalties and taxes at the time they are due. But it turns out that some of these novel and unforeseeable interpretations make it impossible even theoretically for us to have paid the "correct" amount when we filed our returns.

Regardless of how or when the disputes over past taxes are resolved, the State needs to establish transparently clear rules about what we should be paying now for our current taxes. Tell us how to figure the right amount to pay, and we will pay it. But don't make us try to guess what someone years from now will think is the right amount. To give us stability, these rules need to be made in such a way that they will be applied consistently both today and in the future.

But I have not come here to complain about how the tax laws are being interpreted and applied, or to complain about seemingly endless litigation. So, let me return to the fundamental economic realities of the decline in North Slope oil production, which I was discussing. What I was saying earlier is that substantial, ongoing new investments in the fields can improve the revenue side of the economic picture by slowing down the rate of decline in production. Here is a graph depicting this.

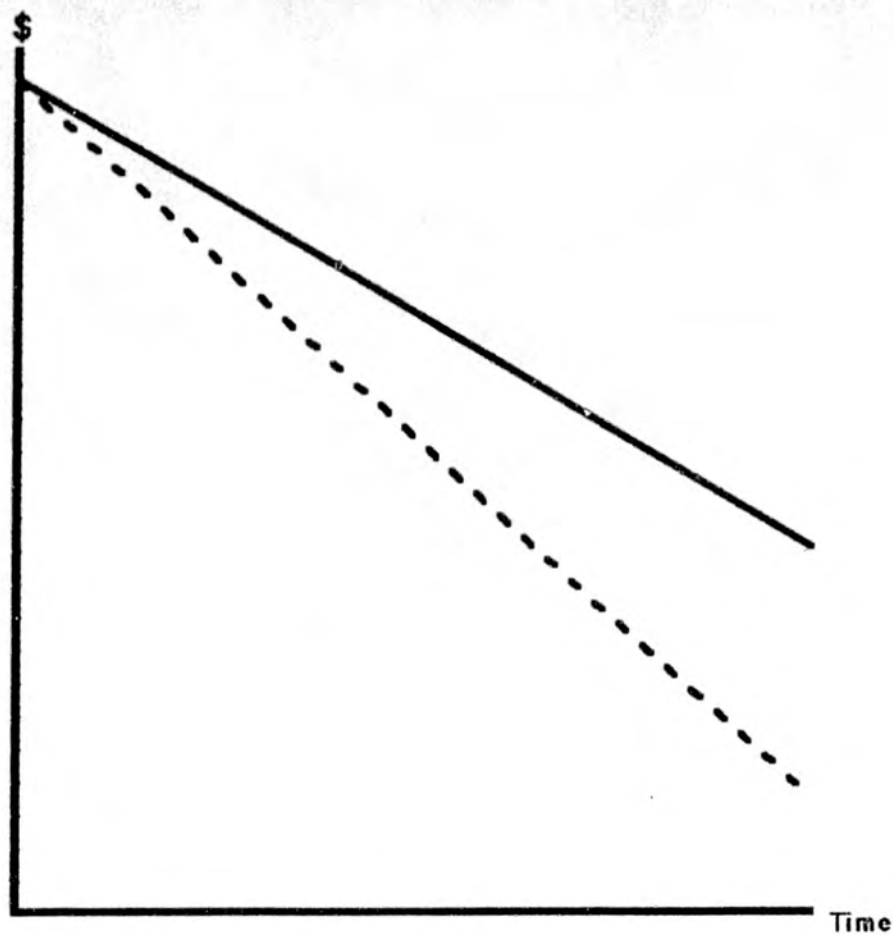


Figure 9. Slowing the Rate of Decline

What the new investments will do is shift the decline in the revenue side of the equation so that it falls off less steeply. But when you look at the cost side as well as the revenue side --

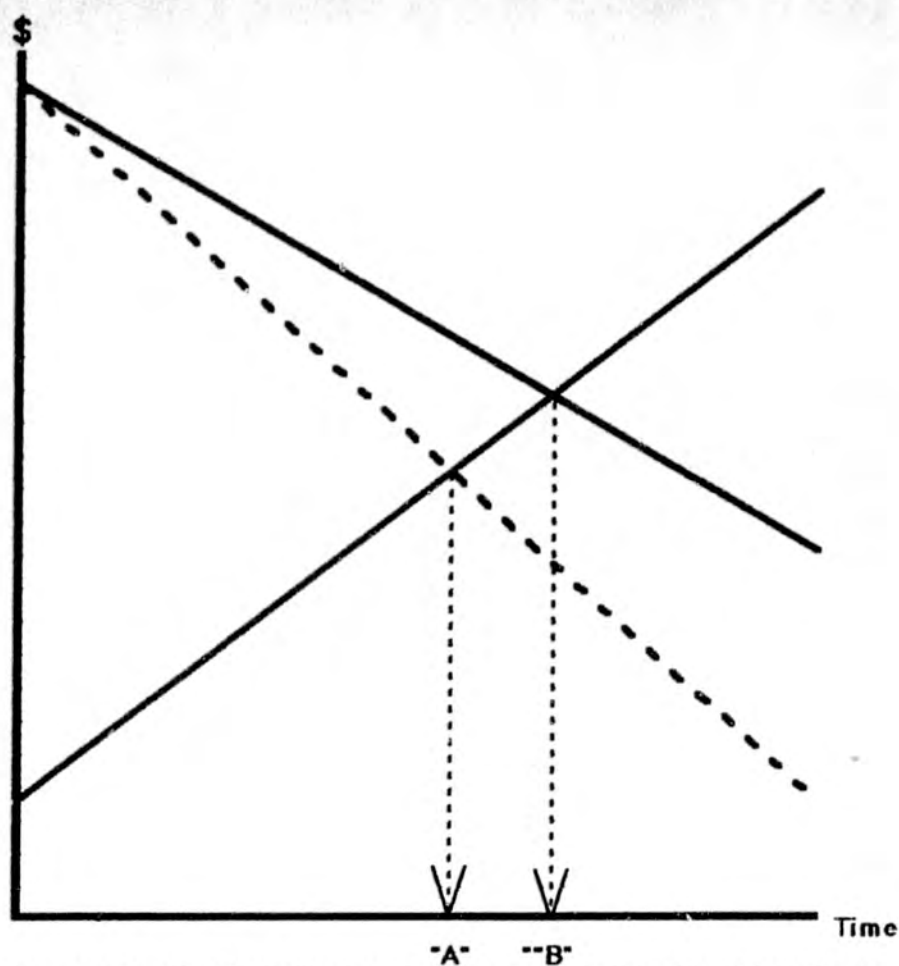


Figure 10. Effect of Slowing Decline for a Field with Rising Costs

you can see that new investments do not solve the problem. They only delay the "day of reckoning" from time "A" to time "B."

This means we have to work on the cost side of the equation as well. As I noted, the historic trend for operating costs has been a steady and continuous increase. Simply to arrest operating costs at their present level would be something of an achievement.

However, the only option that offers any chance of fully realizing the potential of the North Slope fields is to reverse the rising trend in costs and make them actually decline.

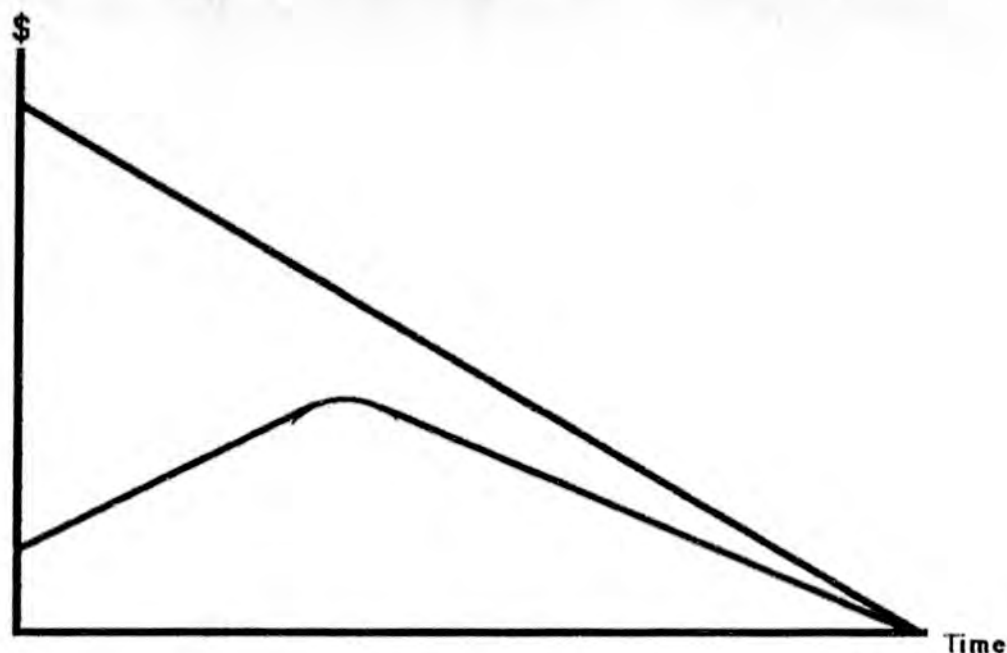


Figure 11. Saving a Declining Field by Reversing the Rising Cost Trend

This is the reality that the Prudhoe curve imposes on us. Declining production means that we have to get better control over our operating costs and reverse their historic tendency to rise. We at BP, like our counterparts at ARCO, have no choice but to operate in a new mode -- leaner, more efficient, smarter.

One of the first and most important initiatives to operate smarter on the Slope was the Shared Services Agreement between ARCO and BP for Prudhoe Bay operations. If both companies are performing some function on their respective sides of the field and there are economies of scale to be realized by combining those separate activities, the Shared Services Agreement calls for the two to be combined. It simply does not make sense to keep doing things separately when it would cost less to combine them. Our compelling economic situation overrides the sense of "turf" and rivalry that otherwise exists between two companies that are, after all, competitors. The Shared Services Agreement also calls on both companies to rethink their work practices and adopt the most efficient approach regardless of its source -- whether ARCO, BP, or anybody else.

BP is also changing the way it does business with its contractors. Some 80% of our operating costs are paid to outside contractors, so clearly any improvements we can achieve in efficiency with them can go a long way towards reversing the trend in operating costs. As Julian Darley told The Alliance in January:

"We're seeking partnerships with our suppliers that are truly collaborative -- ones driven by *value*, where *price* is only one of the components.

"A business partnership is a marriage. It has to be a win-win situation, or it won't work."

Too often and for too long, our contractors have not had a real understanding of BP's actual needs. This was mostly because we didn't tell them. We only said, "Here's what we want. How much will it cost?" Our new approach takes more effort on our part -- our people have to sit down with the bidders and explain not only **what** we want but **why** we want it. We at BP simply don't know our contractors' business as well as the contractors themselves know it, and so they must be able to tell us when they see something better than what we're asking for. This is what we mean by "collaborative partnering," and it's just another way for us to be smarter in the way we do business.

A third way for us to reduce our operating costs is to re-examine and challenge those things that we do in-house. Are these things really activities that BP is particularly good at doing? Are they things that BP should be doing itself? Are there external businesses that provide the same services and at less cost? We are finding that quite a lot of work we have been doing internally is really not part of what our business is all about. And so we are turning to outside sources for that work. This process has been given the inelegant name of "outsourcing." It is merely another way we have found to smarten up the way we do business.

Another way to do business smarter is to eliminate outright the lower-value activities performed by our staff. We must continually review what we are doing and question whether value is truly being added by these activities. We must search for ways to accomplish the same results with fewer people. Over the past few years we have moved many functions to Alaska that were previously performed Outside, and at the same time have steadily reduced the number of staff required overall. This has not been easy for us -- in fact the experience is quite painful, and we can sympathize with what the State must go through in cutting its spending back to a sustainable level. But we find there is little choice but to continue to reduce staff in this new era of declining production.

These initiatives -- the Shared Services Agreement with ARCO, partnering with our contractors, outsourcing, and staff reductions -- are manifestations of BP's commitment to remain in Alaska, for it is only by taking these and similar steps that we fully develop the resources that are here. Ironically, these very initiatives seem to be the source for the suspicion that we are about to leave. People have misunderstood the Shared Services Agreement as being a transfer of our operating functions over to ARCO, not as a way for both companies to save money. They see partnering as a way of cutting back on the scope of work we're doing, rather than as a way for both our partners and ourselves to benefit from working more closely together. They mistake outsourcing and staff reductions as signs that BP is withdrawing its business activity from the state. As I have explained, all these initiatives are our only way of coping with the economic reality being forced on us by the decline of North Slope production.

And here, too, there is an area where the State of Alaska can help us. As an unavoidable consequence of declining production, BP's focus, and that of our partners in the North Slope fields, must be to prioritize our expenditures, spending money on those projects that produce a return on our investment. It follows, then, that investments in projects that do not generate any return should only be made when there is a clear need for them.

At BP we pride ourselves for our efforts to be leaders among the industry in protecting health, safety and environmental quality. Our management are sincerely committed, at a personal level as well as corporately, to the pursuit of these goals. It is simply good business, as well as responsible corporate citizenship, for industry to make the investments necessary to protect and promote public health, safety and environmental quality. But, as Alyeska president James Hermiller told the Anchorage Chamber of Commerce last January:

"Regulatory controls should not be required merely because technology exists to do the job. Agencies must consider benefits versus costs."

And it is not good for the State to ignore the benefits versus costs, either. Again, as Mr. Hermiller pointed out:

"A good rule of thumb is that for every dollar Alyeska spends, the dollars received by the state for severance taxes and royalty payments are diminished by 25 cents, and the value of all production, including royalty oil, is reduced by one dollar."

The same is true whether the dollar is spent for TAPS, or for the marine terminal, the tankers or some other transportation facility. But, more fundamentally, the increased cost of doing business -- whether in the transportation sector or in the production operations -- becomes an economic drag that ultimately tends to reduce the rate of production and prevent the full recovery of the reserves. There will simply be less production on which royalty and production taxes are paid.

But please do not misunderstand me. We absolutely are not asking for a license to despoil the environment and imperil the health and safety of the public. By all means, protect the environment and people's well being. All we are suggesting is that, in this era of declining production, the State should work closer **with** us, instead of **against** us, to ensure that the justification is real, not illusory, before requiring us to make the investment. To the extent the State and industry share the same goals -- producing as much as possible while preserving and protecting health, safety and environmental quality -- the process of regulation should be more like a partnership than a confrontation.

I hope that by explaining what BP is doing and why we are doing it, I have dispelled the fears about our intentions. As I said at the beginning of these remarks, BP is committed to Alaska. We are not about to leave. We hope to be here for as long as the State will let us remain, so the tremendous petroleum resources here can be fully developed and produced.

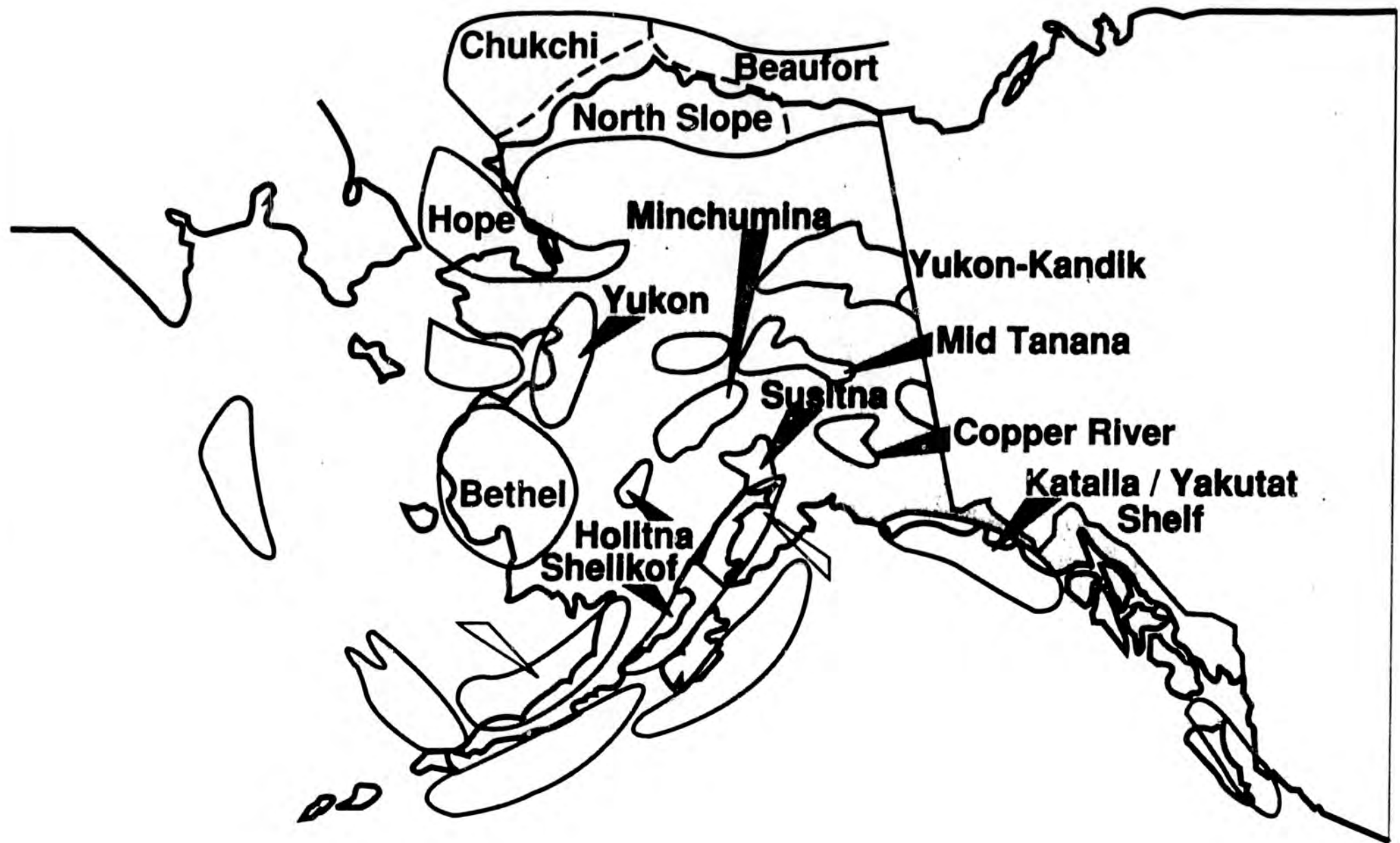
Our actions are the best proof we can offer of our enduring commitment to Alaska. We are striving to convert still more of the petroleum **resource** into recoverable **reserves**, not only at Prudhoe Bay but for all the fields on the North Slope. We are relentlessly seeking for ways to do our business smarter. So far we have found Shared Services with ARCO, collaborative partnering with our outside vendors and contractors, outsourcing of functions that others do better than we, and achieving more ourselves with fewer people -- and we are still looking. We have

focused our exploration activities on those areas of Alaska that best fit our expertise, experience and business objectives. We seek a reinforcement of the partnership industry has with the State of Alaska and its people.

These are not the deeds of someone who is about to get out of Alaska. And as our slogan says, it is "deeds, not promises" that count.

Thank you for this opportunity to address the Committee.

Alaska Sedimentary Basins



SCOMM

78:11

STATE OF ALASKA

WALTER J. HICKEL, GOVERNOR

DEPT. OF ENVIRONMENTAL CONSERVATION

DIVISION OF SPILL PREVENTION AND RESPONSE
410 Willoughby Avenue, Suite 105
Juneau, AK 99801-1795

Telephone: 465-5250
FAX: 465-5244

March 20, 1992

Ms. Ginny Faye
Senator Cotten's Office
P. O. Box V, Capitol, Rm 11
Juneau, AK 99811

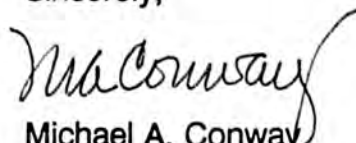
Dear Ms. Faye:

Thank you for scheduling a joint briefing for the legislature on the Spring 1992 Exxon Valdez clean-up operation. I understand the briefing is set for 10:30 a.m., on April 14.

The briefing will be done by Commissioner Sandor, Admiral Ciancaglini (U.S. Coast Guard, FOSC), and David Kennedy (NOAA Scientific Support Coordinator). Exxon will have a representative available to answer questions.

Enclosed are copies of draft documents which provide you an idea of the information to be presented at the joint legislative briefing.

Sincerely,


Michael A. Conway
Director

MAC/sjn (SPAR-faye.104)

Enclosure: As stated

cc: Janice Adair, Acting Director, Division of Administrative Services

MEMORANDUM

STATE OF ALASKA

Department of Environmental Conservation

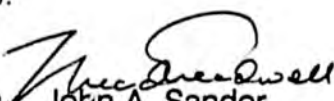
TO: The Honorable
Senator Sam Cotten
Chairman, Senate Oil and
Gas Committee

DATE: April 14, 1992

FILE NO: SPAR-cleanup.mem

THRU:

TELEPHONE NO: 465-5000

FROM: 
John A. Sandor
Commissioner

SUBJECT: Exxon Valdez oil spill 1992
cleanup operations

Those joining me to brief the Legislature on the 1992 shoreline survey and cleanup activity for the Exxon Valdez oil spill will be:

- Rear Admiral David Ciancaglini, Federal On-Scene Coordinator
- Dr. Rober Pavia, NOAA's Chief Scientific Support Coordinator and advisor to the Federal On-Scene Coordinator

Also attending the briefing this morning who are available to answer questions are:

- Simon Mawson, ADEC Regional Administrator, Pipeline Corridor Region and State's On-Scene Coordinator
- Commander Dennis Maguire, Deputy Federal On-Scene Coordinator
- Mead Treadwell, Deputy Commissioner, ADEC
- Michael Conway, ADEC Director, Spill Prevention and Response Division
- Joseph Talbott, NOAA Exxon Valdez Project Manager
- Robert Forgit, Federal On-Scene Coordinator's Office
- Chipper Loggie, Exxon Alaska Operations Planning Manager
- Jim Sheenan, Exxon Advisor

Thank you for the opportunity to brief the Legislature on this matter.

MAC/rr

INTRODUCTION - COMMISSIONER SANDOR (5 MIN)

BRIEFING TO ALERT YOU OF THE UPCOMING END OF THE CLEANUP.

COMMENTS TODAY WILL BE CONFINED TO THE CLEANUP.

RESTORATION AND HOW RESTORATION FUNDS WILL BE ALLOCATED WILL BE ADDRESSED AT A SEPARATE BRIEFING.

That briefing will be conducted by ADEC...

CLEANUP NEARLY COMPLETE BASED ON 1991 CONDITIONS.

Prior to the 1991 cleanup, less than 1% of the spill-impacted shorelines had evidence of oil

Residual oil still exists in some locations, but what remains is weathered and does not pose a threat to the environment

The cleanup's success is due in large part to the efforts of FOSC, SOSC and Exxon, assisted by nature

SHORELINES MUCH IMPROVED AND RECOVERY UNDERWAY.

The improvement in shoreline conditions is evident

Dave Kennedy of NOAA will discuss current conditions

COMMERCIAL FISHING HARVESTS ARE AT OR EXCEED PRE-SPILL LEVELS.

Very successful 1990 and 1991 commercial fish harvests in PWS

1992 SHORELINE ACTIVITIES SCHEDULED FOR MAY 15 - JUNE 15.

1992 shoreline activities have been agreed to by FOSC, SOSC & Exxon

Portions of 64 subdivisions have been jointly identified for the survey

Low intrusion manual cleanup will be performed as needed at the time of the survey

Admiral Ciancaglini will address the 1992 survey and cleanup plans

EXPECT SURVEY TO CONFIRM CLEANUP PHASE IS COMPLETE.

Cleanup has been successful in removing oil that might be harmful

Further removal would cause more harm than good

Combination of cleanup and resilience of nature is resulting in a rapid recovery

Federal and State standards for ending the cleanup effort will likely be reached this summer

Admiral Ciancaglini and I will discuss the process of concluding the cleanup

USCG/EXXON INVOLVEMENT STOPS WITH END OF CLEANUP.

Parties have worked well together and done a good job

USCG/DEC/Exxon worked closely together under difficult circumstances to accomplish the cleanup

Throughout the cleanup, work recommendations were developed via a joint review process with input from all interested parties

Consensus reached on essentially all work

The system evolved and improved over time

USCG/Exxon involvement stops with the successful completion of the cleanup

We should recognize the unprecedented efforts of all involved in the cleanup

The initial response has mitigated the impact of the spill on our environment

INTRODUCE DAVE KENNEDY

Dave Kennedy of the National Oceanic and Atmospheric Administration has worked on the scientific aspects of the spill since
He will update you on current conditions

CURRENT CONDITIONS - DAVE KENNEDY (15 MIN)

RECOVERY IS PROGRESSING IN ALL AREAS IMPACTED BY SPILL.

NOAA study shows significant recovery in all areas
Recovery rates vary throughout the spill area but recovery is evident on even those areas which had been most severely impacted
Recovery is well advanced compared to our experience with other spills
Due to the nature of PWS and the cleanup effort

OVERALL WATER QUALITY NOT AFFECTED BY THE SPILL.

Water column chemical analysis in 1989 revealed hydrocarbon concentrations at background levels shortly after the spill

SUBSISTENCE FOODS SAFE TO EAT

Oil Spill Health Task Force studies indicate that hydrocarbon concentrations found in traditional subsistence foods collected in areas impacted by the spill cannot be distinguished from those found in samples collected at unoiled sites

COMMERCIAL FISHING ACTIVITY RETURNED TO PRE-SPILL LEVELS IN 1990.

Very successful commercial harvests in 1990 and 1991
1991 seine herring harvest (11,923 tons) was second largest on record and the largest herring harvest in a decade
1991 pink salmon harvest (more than 37 million fish) was the second largest on record and 30% higher than the record pre-spill catch.
1990 record of 44 million salmon eclipsed previous record of 29.2 million

NO RESTRICTIONS ON USE OF SHORELINES IMPACTED BY SPILL.

Remaining oil is not deterring recolonization
Shoreline aesthetics much improved (less visible oil with each passing year)
Human and wildlife use of impacted areas is returning to pre-spill levels
(could use figures on tourism/recreational use)

LITTLE OIL REMAINS ON THE SHORELINES.

1991 survey focused on locations where remaining oil was anticipated
The survey identified only 120 locations, or 20% of 585 surveyed, where treatment was judged to be beneficial by the FOSC
An additional 27 locations were resurveyed or had work done at the request of the SOSC
Following the 1991 cleanup it was determined that 64 subdivisions should be reexamined in the spring of 1992

SMALL POCKETS OF SUBSURFACE OIL REMAIN IN HARDEST HIT AREAS.

The sites with subsurface oil are limited to portions of Prince William Sound
Pockets of subsurface oil are getting smaller and more discontinuous each year

REMAINING OIL POSES LITTLE THREAT TO ENVIRONMENT OR HUMAN HEALTH

Remaining oil is scattered and discontinuous

Oil is essentially immobile

Small, infrequent, highly localized sheens may occur if subsurface oil pockets are disturbed by wave action or physical intrusion

Resulting sheens are highly weathered and have no significant impact on the environment

Toxicity is significantly reduced due to weathering and lack of mechanism for exposure

The remaining oil is not hindering natural recovery

CONCLUSION

As a result of natural processes augmented by three summers of cleanup activity, all areas impacted by the 1989 spill are in an advanced state of recovery

INTRODUCE ADMIRAL CIANCAGLINI

SPRING SURVEY - ADMIRAL CIANCAGLINI (10 MIN)

FOSC WILL CONTINUE TO DIRECT THE ASSESSMENT AND CLEANUP EFFORT.

The spill response continues under federal direction

The joint processes we have developed over the last three years continue to be effective

Cleanup costs expected to be less than \$5 million

Payment will come from settlement funds

REASSESS KEY AREAS PRIOR TO END OF CLEANUP PHASE (MAP).

Based on last year's conditions, we've identified the areas which should be reassessed prior to terminating the cleanup phase

Please refer to the map in the handout package

Note that only a few of the hardest hit areas still require assessment

We are looking at specific locations within the segments

FOSC, SOSC & EXXON JOINTLY IDENTIFIED PORTIONS OF 64 SUBDIVISIONS TO ASSESS FOLLOWING 1991 CLEANUP.

Only specific sites in the subdivisions will be visited

Exxon role is that of a technical advisor/consultant to FOSC

SURVEY WILL BE CONDUCTED 15 MAY - 15 JUNE.

This will allow sufficient time to survey and cleanup any remaining troublesome spots

TWO VESSEL BASED 11 PERSON TEAMS, PLUS 1 HELICOPTER.

Very experienced personnel from prior years

USCG, ADEC, NOAA, land manager, biologist, oil geomorphologist, Exxon, photographer, and two cleanup workers

CLEANUP DECISIONS WILL BE MADE JOINTLY ON THE SHORELINES.

The process will be simplified this year

The survey team will make on-site cleanup decisions as the survey is conducted

THE SURVEY AND CLEANUP WILL BE ACCOMPLISHED SIMULTANEOUSLY.

The two cleanup workers on each team will be able to deal with the situations we expect to encounter as they are directed by the survey team

LOW INTRUSION MANUAL CLEANUP ONLY.

No environmental or cost benefit from removal or mechanical work

No bioremediation expected because of advanced oil weathering

END-OF-CLEANUP FACTORS-ADMIRAL CIANCAGLINI (5 MIN)

INTRODUCTION

This will be the last summer of cleanup

You should be familiar with the criteria used to make this decision

NO MORE OIL ON THE WATER OR LIKELY TO REACH THE WATER.

There has been no oil on the water since 1989, with the exception of small, localized sheens typically associated with cleanup work

The small amount of remaining oil is widely scattered, highly weathered and generally immobile

FURTHER REMOVAL WOULD CAUSE MORE HARM THAN GOOD.

This concept, often referred to as net environmental benefit, is very important

In general, we have reached the point where the damage done by removal far exceeds the benefit

CLEANUP WOULD BE EXCESSIVELY COSTLY COMPARED TO BENEFIT.

With the cleanup costs being paid from the settlement, cost effectiveness continues to be a concern

ATTAINMENT OF ABOVE EXPECTED THIS SUMMER.

Based on our experience over the last few years, we expect the shoreline survey to confirm that the cleanup has been successful

Coast Guard/Exxon involvement stop with the end of the cleanup

COMMISSIONER SANDOR WILL CONCLUDE OUR REMARKS

CONCLUSION - COMMISSIONER SANDOR (5 MIN)

THE CLEANUP IS COMING TO A SUCCESSFUL CONCLUSION.

As Dave Kennedy and Admiral Ciancaglini have said, this has been an unprecedented cleanup effort

STATE REQUIREMENTS FOR END-OF-CLEANUP ARE SIMILAR TO FEDERAL REQUIREMENTS.

The state uses a net environmental benefit criteria

Cleanup is complete if the cleanup activities would result in greater environmental damage than the discharge itself

ALL SOSC WORK REQUESTED IN 1991 WAS COMPLETED.

Last year, working closely with us, the FOSC was able to accommodate all additional requests from the State

I expect this will again be accomplished in 1992, so that both Federal and State requirements for cessation of the cleanup will be met

STATE AGREES THAT AFTER 1992 ACTIVITIES, SHORELINE CONDITIONS WILL BE SUCH THAT THE CLEANUP PHASE IS OVER.

Our assessment is that these requirements will be met by June 15, 1992

DEC has a program in place to monitor certain sites over time

UPON COMPLETION, USCG AND EXXON INVOLVEMENT WILL END.

Their involvement is limited to the cleanup

They have agreed to joint development of a publication and video which will summarize the cleanup and current conditions

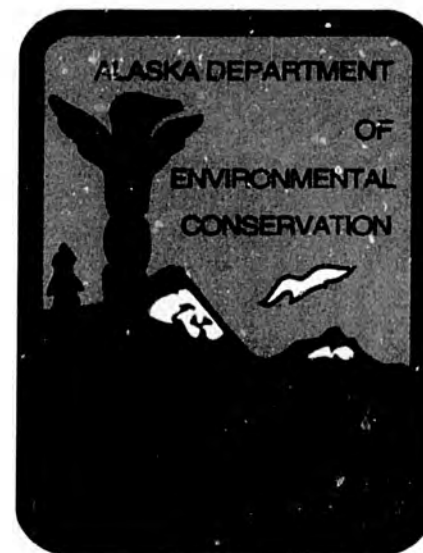
We will provide them to you after the cleanup ends

AT THIS TIME, WE WOULD GLADLY ADDRESS ANY QUESTIONS YOU MIGHT HAVE ABOUT THE CLEANUP OR CURRENT CONDITIONS

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3/5/92

EXXON VALDEZ CLEANUP BRIEFING



APRIL 14, 1992

**EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992
INDEX**

PRESENTATION

**INTRODUCTION
CURRENT CONDITIONS
SPRING SURVEY
FEDERAL CLEANUP STANDARDS
CONCLUSION**

SUPPORTING MATERIAL

**1989-1991 SURVEY RESULTS
1992 SUBDIVISIONS TO BE SURVEYED
1992 SURVEY MAPS
1992 SURVEY TEAM MAKEUP
1992 COST PROJECTION
SUBSISTENCE FOOD TASK FORCE FINDINGS**

**EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992**

INTRODUCTION - COMMISSIONER SANDOR (ADEC)

PURPOSE

- o BRIEFING TO ALERT YOU OF THE UPCOMING END OF THE CLEANUP
- o COMMENTS TODAY WILL BE CONFINED TO THE CLEANUP
- o RESTORATION AND HOW RESTORATION FUNDS WILL BE ALLOCATED WILL BE ADDRESSED AT A SEPARATE BRIEFING
- o FEDERAL AND STATE RESTORATION TRUSTEES WILL CONDUCT STUDIES AND IMPLEMENT ANY ACTIVITIES NECESSARY TO RESTORE THE ENVIRONMENT

CONDITIONS

- o CLEANUP NEARLY COMPLETE BASED ON 1991 CONDITIONS
- o SHORELINES MUCH IMPROVED AND RECOVERY UNDERWAY
 - FOR EXAMPLE, COMMERCIAL FISHING HARVESTS ARE AT OR EXCEED PRE-SPILL LEVELS

1992 ACTIVITIES

- o 1992 SHORELINE ASSESSMENT SCHEDULED FOR MAY 15 - JUNE 15
- o EXPECT SURVEY AND CLEANUP ACTIVITY WILL SERVE AS A BASIS TO DETERMINE THE COMPLETION OF THE CLEANUP PHASE
- o USCG/EXXON INVOLVEMENT STOPS WITH THE 1992 CLEANUP
- o RESTORATION STUDIES UNDERWAY

EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992

CURRENT CONDITIONS - DOCTOR PAVIA (NOAA)

- o RECOVERY IS PROGRESSING IN ALL AREAS IMPACTED BY SPILL
- o OVERALL WATER QUALITY NOT AFFECTED BY THE SPILL
- o SUBSISTENCE FOODS GENERALLY SAFE TO EAT
- o COMMERCIAL FISHING ACTIVITY RETURNED TO PRE-SPILL LEVELS
- o NO RESTRICTIONS ON USE OF SHORELINES IMPACTED BY SPILL
- o LITTLE OIL REMAINS ON THE SHORELINES
- o SMALL POCKETS OF SUBSURFACE OIL REMAIN IN HARDEST HIT AREAS
- o REMAINING OIL POSES LIMITED THREAT TO ENVIRONMENT OR HUMAN HEALTH

**EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992**

SPRING SURVEY - ADMIRAL CIANCAGLINI (USCG)

- o FOSC WILL CONTINUE TO DIRECT THE ASSESSMENT AND CLEANUP EFFORT
- o REASSESS KEY AREAS PRIOR TO END OF CLEANUP PHASE (MAP)
- o FOSC, SOSC & EXXON JOINTLY IDENTIFIED PORTIONS OF 64 SUBDIVISIONS TO ASSESS FOLLOWING 1991 CLEANUP
- o SURVEY WILL BE CONDUCTED 15 MAY - 15 JUNE
- o TWO VESSEL BASED 11 PERSON TEAMS, PLUS 1 HELICOPTER
- o CLEANUP DECISIONS WILL BE MADE JOINTLY ON THE SHORELINES
- o SURVEY AND CLEANUP WILL BE ACCOMPLISHED SIMULTANEOUSLY
- o LOW INTRUSION MANUAL CLEANUP ONLY

**EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992**

FEDERAL CLEANUP STANDARDS - ADMIRAL CIANCAGLINI

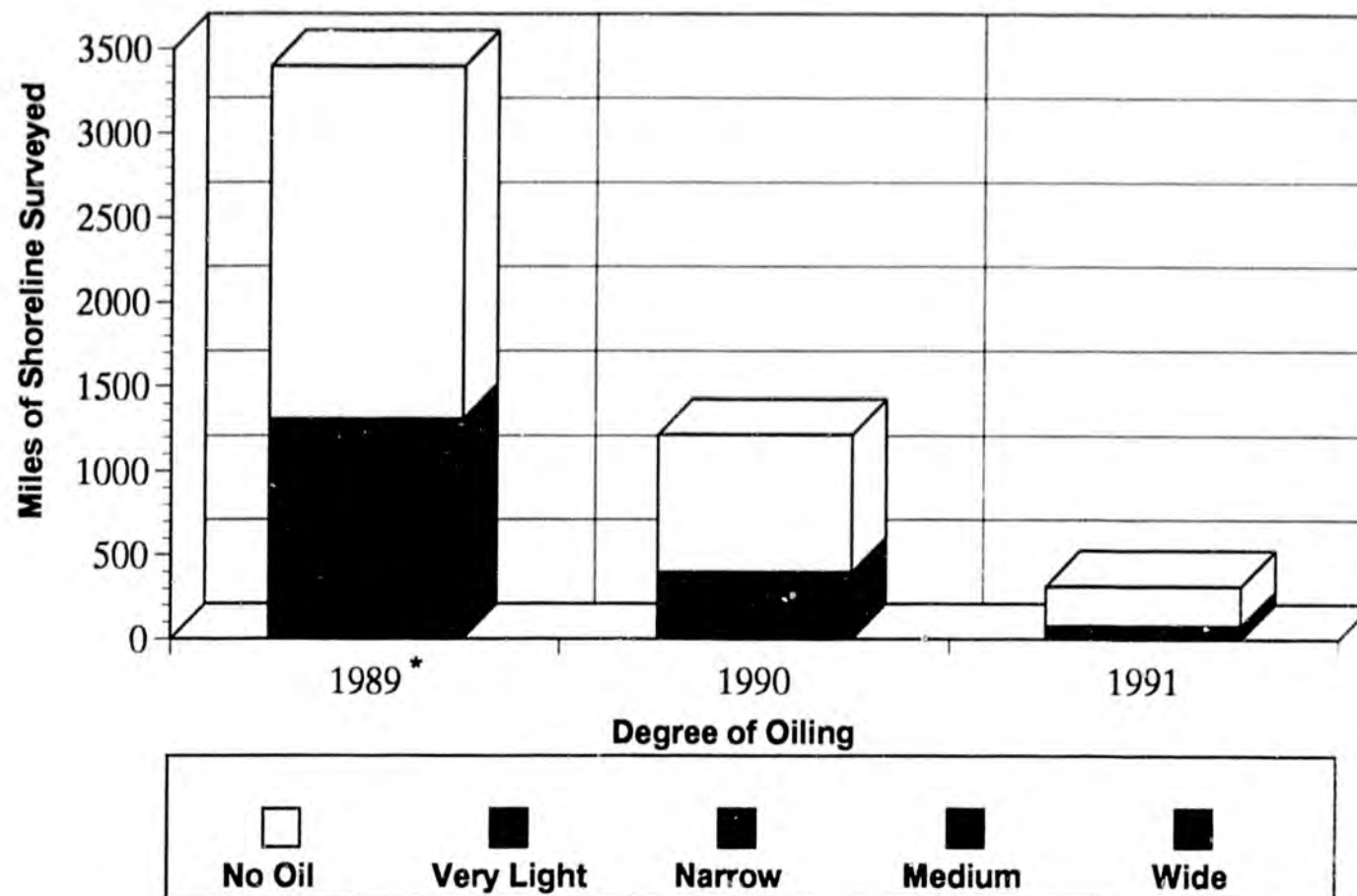
- o NO MORE OIL ON THE WATER OR LIKELY TO REACH THE WATER
- o FURTHER REMOVAL WOULD CAUSE MORE HARM THAN GOOD
- o CLEANUP WOULD BE EXCESSIVELY COSTLY COMPARED TO BENEFIT
- o ATTAINMENT OF ABOVE EXPECTED THIS SUMMER

**EXXON VALDEZ CLEANUP BRIEFING
APRIL 14, 1992**

CONCLUSION - COMMISSIONER SANDOR

- o THE CLEANUP PHASE IS COMING TO A SUCCESSFUL CONCLUSION
- o STATE REQUIREMENTS FOR END-OF-CLEANUP ARE SIMILAR TO FEDERAL REQUIREMENTS
- o ALL SOSC WORK REQUESTED IN 1991 WAS COMPLETED
- o STATE EXPECTS THAT AFTER 1992 ACTIVITIES, SHORELINE CONDITIONS WILL BE SUCH THAT THE CLEANUP PHASE IS OVER
- o UPON COMPLETION, USCG AND EXXON INVOLVEMENT WILL END
 - MUTUAL WORK ON PUBLICATION AND VIDEO WILL CONTINUE
- o FEDERAL AND STATE RESTORATION TRUSTEES WILL CONTINUE TO TAKE WHATEVER ACTIONS THEY DEEM APPROPRIATE TO RESTORE THE ENVIRONMENT

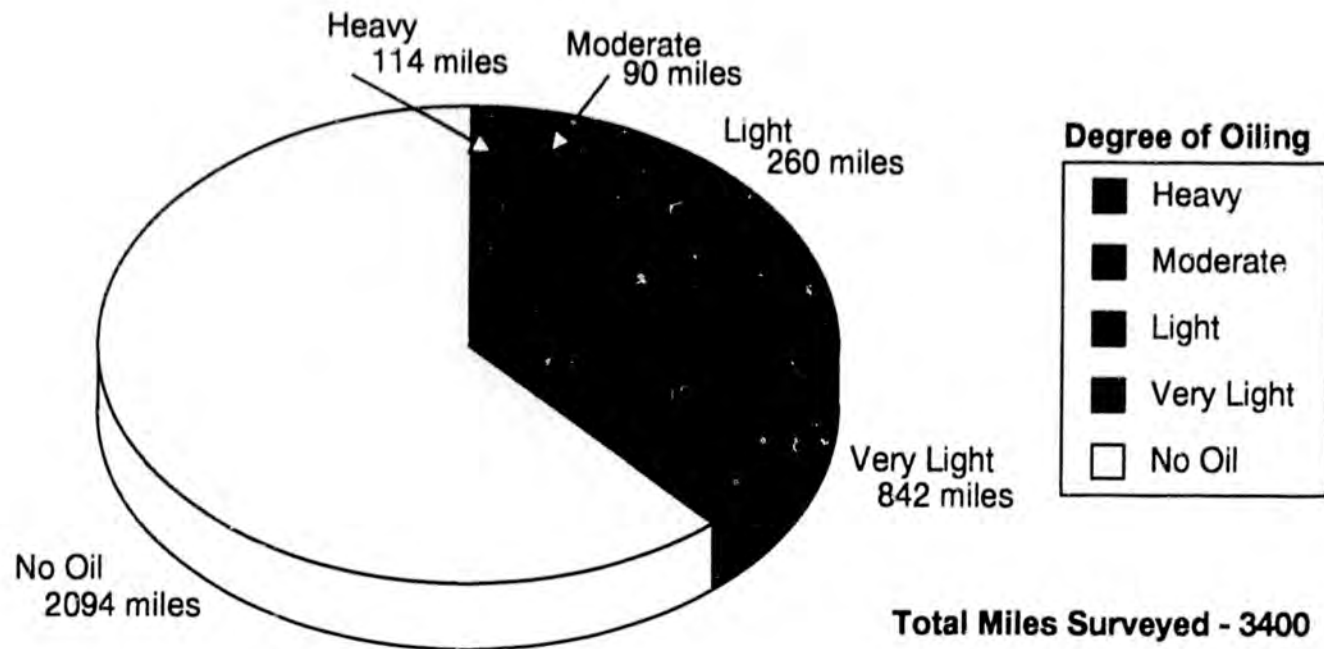
A Comparison of Shoreline Oiling in Miles 1989, 1990, 1991



* 1989 data was categorized as follows:

No Oil Very Light Light Moderate Heavy
These categories are not directly comparable to those used in 1990 and 1991.

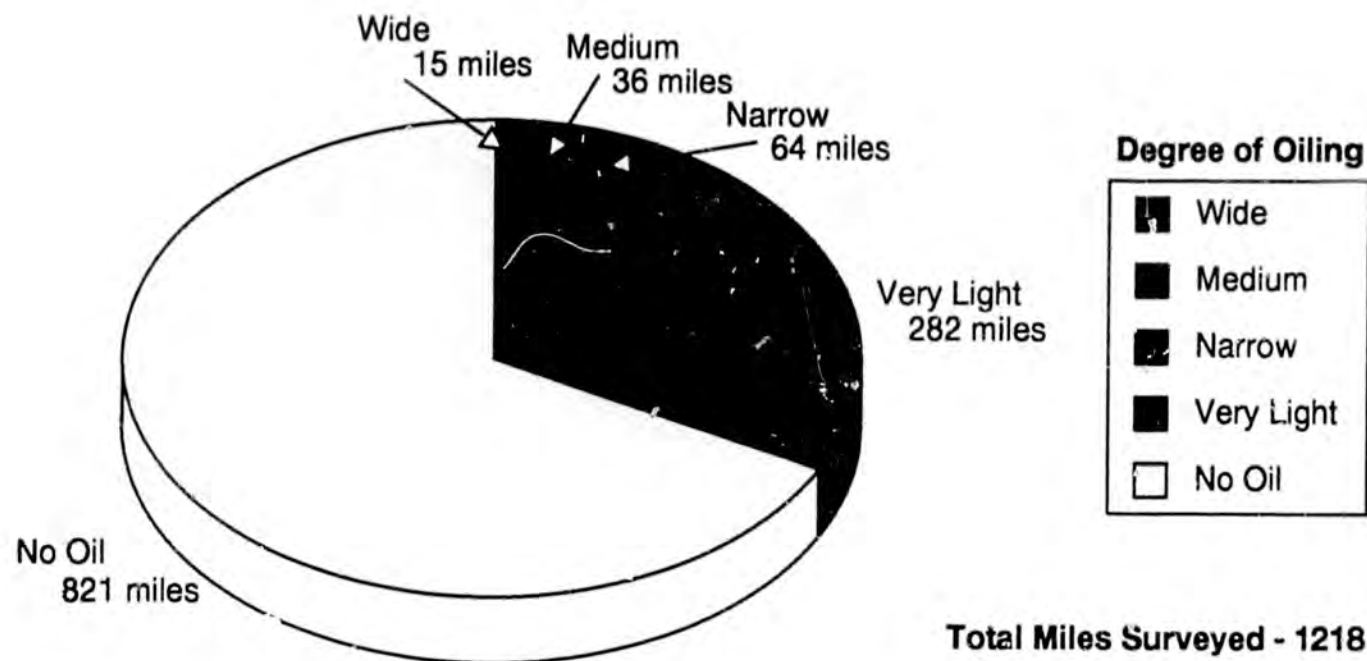
Degree of Shoreline Oiling in Miles 1989 Survey



Degree of Oiling	Beach Width Affected	Total Miles
Heavy	> 6 Meters	114
Moderate	3-6 Meters	90
Light	< 3 Meters	260
Very Light	any width with < 10% cover	842
No Oil		2094
Total Surveyed		3400

Based on Shoreline Cleanup Assessment Team survey (SCAT).

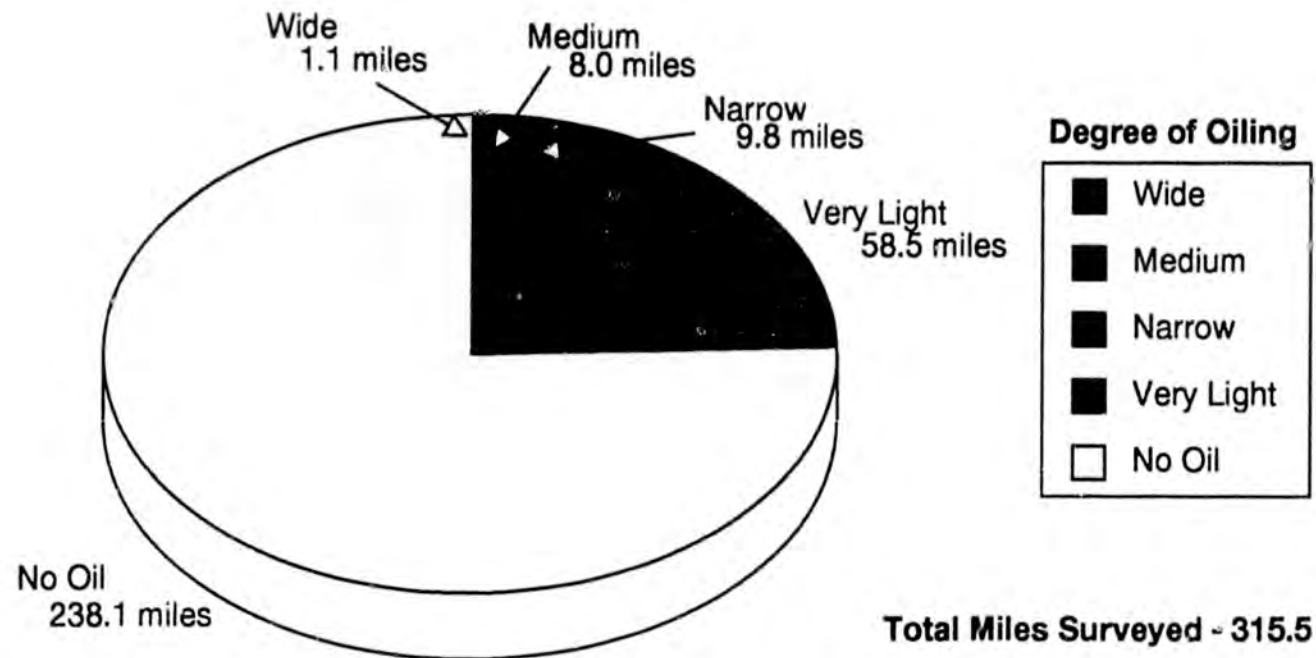
Degree of Shoreline Oiling in Miles 1990 Survey



Degree of Oiling	Beach Width Affected		% Oil Cover	Total Miles
Wide	or	> 6 Meters	and > 50%	15
Medium		> 6 Meters	and < 50%	36
		3-6 Meters	and > 10%	
Narrow		< 3 Meters	and > 10%	64
Very Light		Any Amount	< 10%	282
No Oil				821
Total Surveyed				1218

Based on Spring Shoreline Assessment (SSAT).

Degree of Shoreline Oiling in Miles 1991 Survey



Degree of Oiling	Beach Width Affected		% Oil Cover	Total Miles
Wide	> 6 Meters	and	> 50%	1.1
Medium		and	< 50%	8.0
	or			
Narrow	3-6 Meters	and	> 10%	9.8
Very Light	< 3 Meters	and	> 10%	58.5
No Oil	Any Amount		< 10%	238.1
Total Surveyed				315.5

Based on May Shoreline Assessment Program (MAYSAP).