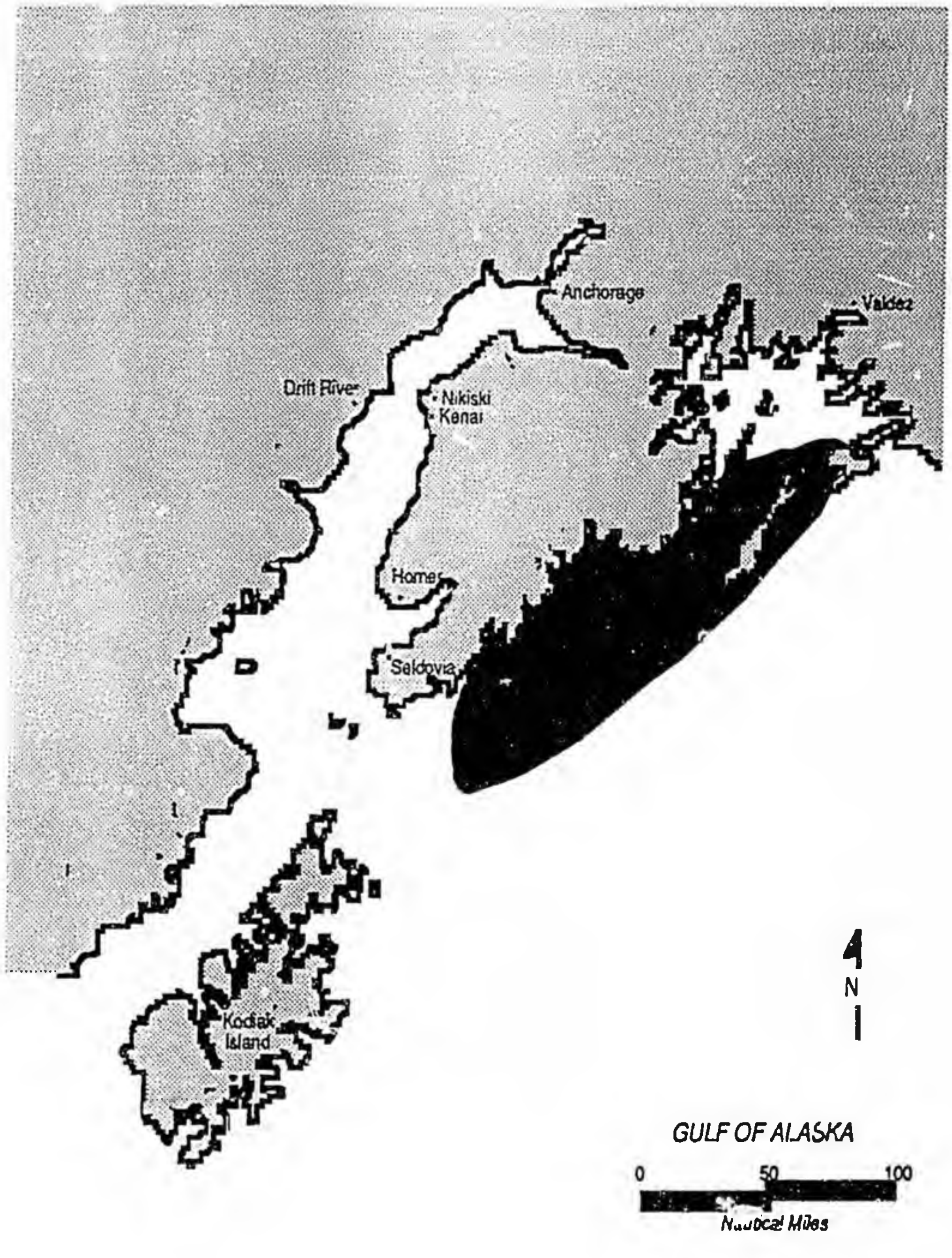
ALASKA LEGISLATURE COMMITTEE FILES, 1989-1990 8672
5956 HOUSE RESOURCES 360

ECO

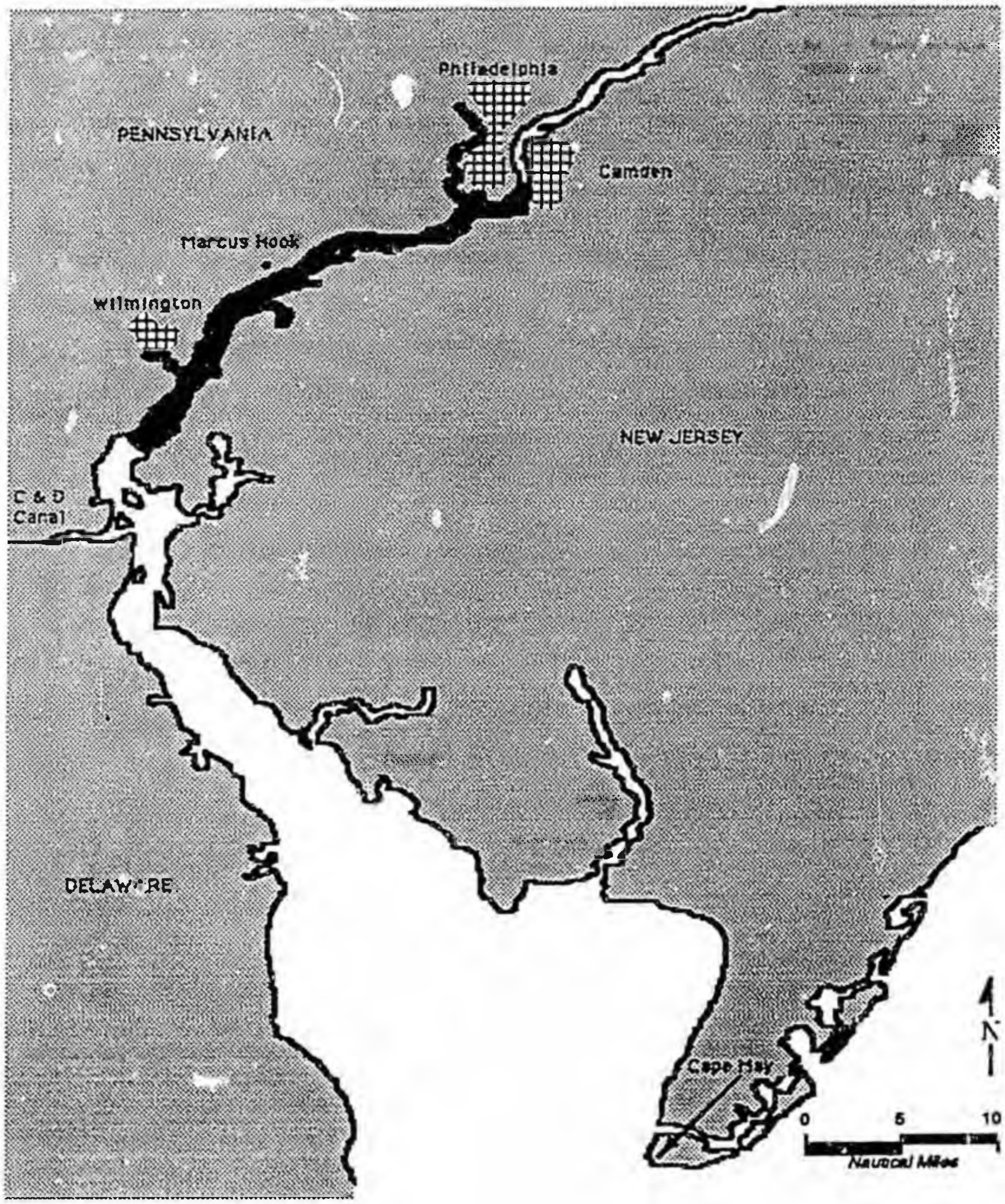
SPILL IN COOK INLET - NIKISKI
9,000,000 GALLONS - 168 HOURS AFTER SPILL

ECO

SPILL AT HINCHINBROOK ENTRANCE
11,000,000 GALLONS - 168 HOURS AFTER SPILL

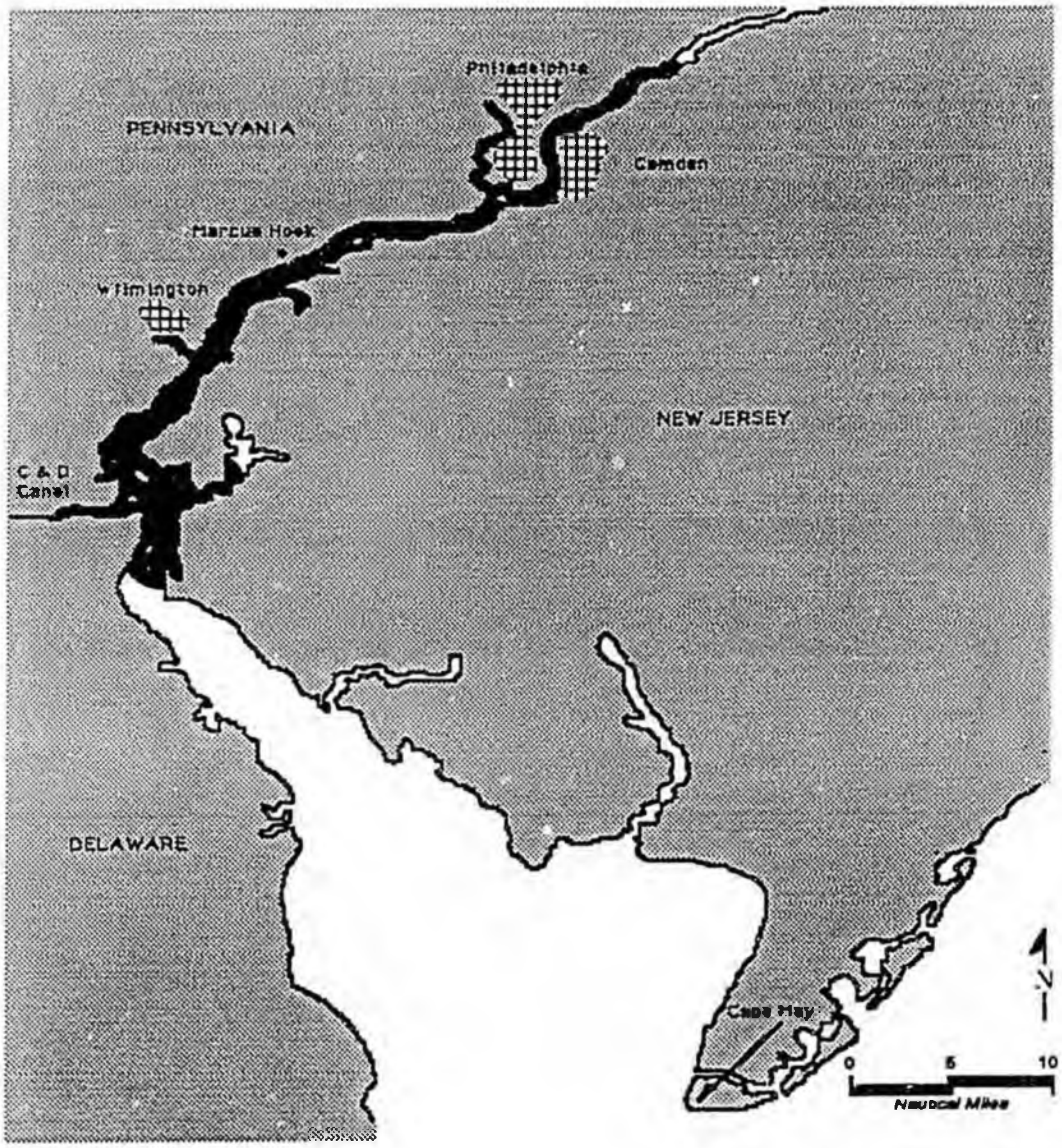


DELAWARE BAY - 24 HOURS AFTER SPILL
SPILL SIZE = 11,J00,000 GALLONS AT MARCUS HOOK
TYPICAL WINTER WIND AND CURRENT CONDITIONS



ECO

DELAWARE BAY - 48 HOURS AFTER SPILL
SPILL SIZE = 11,000,000 GALLONS AT MARCUS HOOK
TYPICAL WINTER WIND AND CURRENT CONDITIONS



NEW YORK - 24 HOURS AFTER SPILL
SPILL SIZE = 11,000,000 GALLONS AT VERRAZANO NARROWS
TYPICAL WINTER WIND AND CURRENT CONDITIONS

13 January 1990

TANKER ADVISORY CENTER, INC.

FAX (907) 463-5661

Rep Davidsons Office?

Mr. Jay Nelson
Alaska Oil Spill Commission
Juneau, Alaska

Dear Mr. Nelson:

As discussed on the telephone yesterday, enclosed is a list of steps, in order of priority, to prevent oil spills from tankers.

During my presentation to the Commission on Tuesday 16 January 1990 I plan to focus my discussion on the first item, namely:

Protect cargo tanks with double hulls

Tank locations as Type I Chemical Tanker: Sides B/5, Bottom B/15

Protect all bunker tanks the same as cargo tanks

Strengthen the hull: Scantlings to be 130% of full load draft

Sincerely yours,

Arthur McKenzie

ARTHUR McKENZIE
DIRECTOR

217 EA[illegible] 85 STREET
SUITE 259
NEW YORK, NY 10028

TELEPHONE
212-628-7686

TANKER ADVISORY CENTER, INC.

Prevention of Oil Spills in Order of Priority

- **Use Double Hulls: Type I Spacing, Scantlings 130%**
  Petroleum (Crude oil & products) including bunkers, should be carried only in double hulled vessels with tank locations the same as for Type I chemical tankers. Distance of inner hull from outer hull to be breadth of tanker divided by 5 or 11.5 meters, whichever is less. Height of double bottom must be breadth of tanker divided by 15 or 6 meters, whichever is less. *Scantlings to be 130% of full load draft.*

- **Check Officer/Pilot Competency on Simulators**
  All deck, engine officers and pilots should be tested on simulators at least every two years to determine their competency to handle emergencies.

- **License Tank Vessel Owners/Operators & Key Shoreside People**
  Renewal of licenses to be based partly on safety & pollution performance.

- **Require Oversight of Classification Societies by Elected Officials**
  These quasi governmental Societies, composed of shipowners, builders, insurers & government officials, establish construction and maintenance standards for ships. They are in competition with each other for clients. Vessels' records are confidential. Public oversight by elected officials & access to ship records is required.

- **Wash Dirty Cargo Tanks Only With Oil, Not Water**
  Dirty wash oil can be downgraded &/or reprocessed, avoiding water pollution.

- **Install Voyage Data Recorders on All Ships**
  Lloyd's of London have developed and now sell a 'Black Box' for ships to record automatically vital vessel data for 40 days & then rewrite. The Voyage Data Recorder is ejected if vessel sinks & is recoverable.

- **Use Electronic Charts Showing Vessel's Position**
  Ship's position automatically plotted by radar, Loran or satellite. Alarms warn of dangerous trends. Hydrographic Office can update charts remotely. Low cost Radar reflectors need to be installed in ports and dangerous waterways.

- **Expand Testing for Substance Abuse**
  Test shipboard personnel for substance abuse when applying for license or certificate and for renewals. Test all involved personnel immediately after a casualty. Require reports periodically from Masters & supervisory shore staff commenting on any evidence of substance abuse by personnel on duty.

- **Require Preparation/Approval Operating Manuals**
  Manuals to be prepared by owners and approved by licensing authorities for the operations and maintenance of tank vessels.

13 January 1990

ARTHUR McKENZIE
DIRECTOR

217 EAST 85 STREET
SUITE 259
NEW YORK, NY 10028

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212-628-7686

300. Planning and Response Organization.

301. Spill and Response Activities and Coordination - General.

For pollution response activities, Federal on-scene coordination is accomplished through a single predesignated agent, the OSC, who presents information to and receives advice from the RRT. The EPA and USCG respond to incidents and provide predesignated On-Scene Coordinators (OSCs) within their respective areas. However, DOD will designate OSCs for hazardous substance releases from DOD facilities and vessels. The EPA will provide OSCs for oil discharges and hazardous substances releases into or threatening the inland zone and, unless otherwise agreed, for all planned removals and remedial actions. The USCG will provide OSCs for oil discharges, and for the immediate removal of hazardous substances, pollutants or contaminants into or threatening the coastal zone. The USCG will not provide predesignated OSCs for discharges and releases from hazardous waste management facilities or in similarly chronic incidents

302. Regional Response Team.

A. This Plan uses the Alaska RRT as an advisory body to the OSC which enables Federal, State and local governmental agencies to participate in response to pollution incidents. The primary members include representatives of specified Federal agencies in each state as well as a designated State representative. These members are responsible for the coordination of all input from their respective agencies, as well as providing resources and other available assistance.

B. **Federal Agency RRT Membership:**

Agency	Representative
1. Dept. of Agriculture	U.S. Forest Service, Juneau, AK
2. Dept. of Commerce	National Oceanic and Atmospheric Administration, Anchorage, AK
3. Dept. of Defense	Commander, 6th Infantry Division, Fort Richardson, AK
	U. S. Army Engineer District, Alaska, Anchorage, AK

4.	Dept. of Energy	Richland Operations Office, Richland, WA
5.	Dept. of Health and	HHS, Alaska Area Human Services Native Health Service, Anchorage, AK
6.	Dept. of Interior	Regional Environmental Officer, Anchorage, AK
7.	Dept. of Justice	U. S. Attorney, Anchorage, AK
8.	Dept. of Labor	OSHA, Anchorage, AK
9.	Dept. of State	Department of State, Washington, D. C.
10.	Dept. of Transportation	Commander, Seventeenth Coast Guard District, Juneau, AK
11.	Environmental Protection Agency	EPA Region X, Alaska Operations Office, Anchorage, AK
12.	Federal Emergency Management Agency	FEMA Region X, Bothell, WA

C. State Agency RRT Membership:

1.	Alaska	Department Of Environmental Conservation, Juneau, AK

D. Roles and Responsibilities of Federal RRT Member Agencies

1. The roles and responsibilities of the RRT member agencies are described below. Included also are each agency's resources and types of assistance that may be provided to the OSC. Each agency provides one member and at least one alternate member to the RRT.

2. The Department of Agriculture (USDA) provides expertise in managing agriculture, forest and wilderness areas. The Soil Conservation Service can be helpful in predicting effects of pollutants on soil and their movements over and through soil. The U. S. Forest Service (USFS) has responsibility for certain Federal lands. The USFS can provide local knowledge about communications, logistics, contractors, and equipment availability. They also have in-house radio communications, field housing, and air, land and water transportation capability within their areas.

3. The Department of Commerce (DOC), through the National Oceanic and Atmospheric Administration (NOAA), provides support to the NRT, RRT, and OSC with respect to living marine resources for which it has management authority, including marine fisheries, marine mammals and certain endangered species. They provide meteorological, hydrologic, ice and oceanographic data for marine, coastal and certain inland waters; tide and current information; charts and maps; and satellite imagery. In response to requests from the OSC, NOAA provides on-scene scientific assistance for releases in coastal and marine areas through the regional Scientific Support Coordinator (SSC). (See Section 300.34 for further SSC information.) NOAA acts on behalf of the Secretary of Commerce as a Federal trustee for living and nonliving natural resources in coastal and marine areas. Resources of concern to NOAA include all life stages, wherever they occur, of fishery resources of the exclusive economic zone and continental shelf; anadromous and catadromous species throughout their ranges; endangered and threatened species and marine mammals for which NOAA is responsible; tidal wetlands and other ecosystems supporting these living marine resources; and resources of National Marine Sanctuaries and Estuarine Research Reserves. For resources in coastal waters and anadromous fish streams, NOAA may be a co-trustee with the Department of the Interior, other Federal land managing agencies, and possible Indian tribes as well as the affected state. It will coordinate with co-trustees in investigating damages. Other DOC resources and support that can be provided are described below.

a. Through the National Weather Service (NWS), DOC can provide information on the current and predicted climatological and meteorological conditions at the scene of a significant spill incident. They can provide hydrometeorological observations and forecasts; satellite imagery; use of the NWS communications network and special-purpose aircraft. Site-specific forecasts are available to assist aircraft and ship operations or to provide real-time weather data for pollutant trajectory analyses. Weather Service Forecast Offices (WFSO) responsible for this region are located in: Juneau, Anchorage, and Fairbanks.

b. Through the National Environmental Satellite, Data, and Information Service (NESDIS), DOC can provide satellite imagery of coastal regions. Data buoys can be tracked through the use of the NIMBUS F Satellite. NESDIS can also provide climatological data on marine weather, oceanic conditions, and water column characteristics.

c. The National Marine Fisheries Service (NMFS), provides a broad variety of biological and oceanographic services which can address the impact of spill contaminants and cleanup operations on marine organisms and the marine ecosystem. Such services include population assessments to determine mortalities, laboratory facilities for specific contaminant impact at sublethal levels on marine organisms, and a nationally recognized group of marine pathologists. The regional office maintains extensive contacts with the commercial fishing industry, marine recreational interests, and state fisheries agencies. Chemists and toxicologists may be consulted on properties and toxic potential of various hydrocarbon contaminants to provide information on marine fisheries, marine mammals and certain endangered species to assist in identifying resources at risk and thus determine areas requiring priority protection. Regional personnel alert fishermen to oil slicks and other contamination hazards that may adversely affect fishing operations or equipment.

4. The Department of Defense (DOD) provides representatives from the U. S. Army, and U. S. Army Engineer District, Alaska to the RRT. Resources and assistance available from DOD agencies are outlined below.

a. The U. S. Army [illegible] various military facilities, vehicles, equipment, and, in some cases, aircraft which can be made available in the event of critical incidents. In addition, construction-related equipment may be locally available.

b. The U. S. Army Corps of Engineers (USACE) can provide expertise in all disciplines of engineering. USACE can also provide assistance in the area of dredging, surveying, supply vessels, and manpower. Their expertise can be used for clearing channels, locating obstructions, etc. Activation of USACE resources in support of an RRT activity would be in the form of a written mission assignment which outlines the parameters of work to be done and estimated dollar authority to accomplish the mission.

c. The U. S. Navy is the Federal agency most knowledgeable and experienced in ship salvage, shipboard damage control and diving. The USN has an extensive array of specialized equipment and personnel available for use in these areas as well as for open sea pollution incidents.

5. The Department of Energy (DOE), through its Radiological Assistance Program, provides assistance in recommending radiological control and protective measures. In addition, DOE coordinates Federal radiological assistance through the Federal Radiological Monitoring Assessment Program.

6. The Department of Health and Human Services (HHS).

a. HHS is responsible for providing direct on-scene or indirect assistance for chemical spills and emergencies in which there is a potential or actual threat to the public's health. Such assistance includes health related field guidance and laboratory support, access to toxicology data bases for health and medical data, biological sampling and testing and recommendations for environmental testing.

b. During an emergency response, the OSC may call upon the HHS representative to provide consultation and advice on whether potential or real threats to human health may exist. HHS response capabilities include but are not limited to:

(1) Reviewing available background information on the incident and estimating the potential for human exposure to hazardous substances on-site and to hazardous substances which may have migrated off-site via all pathways.

(2) While on-site, in order to determine if a threat to human health exists, recommending any additional environmental sampling or monitoring procedures needed to define extent of exposure, including identification of persons at high risk or particularly high exposure.

(3) Accessing computerized toxicological data bases through remote video and hard copy terminals maintained by the Center for Disease Control (CDC) and National Library of Medicine. The data base is an interactive data file containing chemical, physical, biological, pharmaceutical, toxicological, and environmental data on approximately 6,000 known and potential toxicants. This system supplements CHRIS and OHMTADS and is a useful source of information during an emergency response.

(4) Providing advice concerning evacuation or taking other preventive measures.

(5) Investigating possible toxic contamination of the food chain.

(6) Outlining potential pathways to human populations based upon soil kinetics/contamination, wind direction, aquifer contamination and/or food chain involvement.

(7) Obtaining and reviewing information regarding allegations of human illness associated with the incident.

(8) Investigating health complaints reported by on-site workers and nearby off-site residents.

(9) Conducting needed health studies which may include any one or a combination of methods, e.g., vital records reviews, review of medical records, administer surveys, conduct clinical examinations, test and analyze human specimens, conduct laboratory and hospital investigations, establish disease/exposure follow-up registries, etc.

(10) Reviewing plans for the safety and health of response workers, and providing advice about operations for compliance with appropriate OSHA regulations for worker safety and health.

(11) Coordinating appropriate health response with Federal, State and local health agencies and the private medical community.

(12) Providing advice and assistance as required by the OSC on health matters in community relations, and dealing with the media.

(13) Coordinating proficiency testing for laboratories analyzing human biological specimens.

7. The Department of the Interior (DOI) provides technical expertise with respect to geology, hydrology, minerals, fish, wildlife, history, and recreation as well as information on lands and resources specifically under its jurisdiction. Within the Department, individual bureaus have specific responsibilities and capabilities as follows:

a. The U. S. Fish and Wildlife Service (FWS) provides expertise on migratory birds, endangered and threatened species, and critical habitats, as well as information on national wildlife refuges and national fish hatcheries. It can resolve problems such as dispersal of birds, habitat identification, protection, damage assessment, and bird rehabilitation, including coordination of volunteers. Liaison with Audubon Society Chapters is maintained by the FWS and can be activated in response to spill incidents involving oiled and injured wildlife. FWS may be able to provide vehicles and boats locally for spill cleanup near national wildlife refuges.

b. The Minerals Management Service (MMS) has expertise in geology, geophysics, petroleum engineering, and oil spill modeling. It also has expertise and responsibility in well control and abatement of pollution sources from Outer Continental Shelf (OCS) oil and gas facilities. It can provide expertise in oil drilling, producing, handling, pipeline transportation, and information from the OCS Environmental Assessment Program. It has access to continuously manned facilities which can be used for command, control, and surveillance of spills occurring from operations conducted under the Outer Continental Shelf Lands Act. MMS can direct a lessee to clean up pollution resulting from its lease activities with their equipment or via direct contract under the authority of OCS Order No. 7 and 30 CFR 250.43. MMS may also coordinate helicopter transportation from a lessee operating in the area during emergencies. The MMS has the authority to suspend any activity within a 500 meter radius of any pollution source for abatement purposes as stated by the Memorandum of Understanding (MOU) of August 16, 1971 between the Departments of the Interior and Transportation. Through the MMS's Offshore Inspection Program, the MMS maintains a representative in each area of drilling activity who could act as the initial Federal observer for a pollution incident related to oil and gas operations. MMS has primary review and approval authority for oil-spill-contingency plans submitted under the Outer Continental Shelf Lands Act, as amended, and authority for regulating air quality which uld result from in situ burning of oil spills on the OCS.

c. The National Park Service (NPS) can provide information on all national parks, monuments, and preserves in Alaska. NPS also provides expertise on historical, archaeological, architectural, recreational, and subsistence resources. NPS may be able to provide local logistical support, such as vehicles, aircraft, and boats for spill surveillance, damage assessment, or cleanup on or near national park lands.

d. The U. S. Geological Survey (USGS) can provide expertise on geologic, geohydrologic, and geochemical resources as well as ground and surface water properties.

e. The Bureau of Land Management (BLM) has responsibility for certain Federal lands and minerals. BLM may be able to provide local logistical support such as camps, vehicles, and aircraft for spill surveillance and damage assessment or cleanup on or near BLM managed land. BLM is responsible for providing the On-Scene Coordinator for Trans-Alaska Pipeline System spills on Federal lands.

8. The Department of Justice (DOJ), through the U. S. Attorney, provides legal advice concerning legal questions arising from discharges, releases, and Federal agency responses.

9. The Department of Labor (DOL), through the Occupational Safety and Health Administration (OSHA), provides advice, guidance, and assistance regarding hazards to persons involved in removal or control of oil or chemical spills.

10. The Department of State (DOS) will lead in developing joint international contingency plans. It will help to coordinate an international response when a pollution incident crosses international boundaries or involves foreign flag vessels. Additionally, DOS will coordinate requests for assistance from foreign governments and offer U. S. proposals for conducting research at incidents that occur off other countries.

11. The Department of Transportation (DOT).

a. On behalf of DOT, the U. S. Coast Guard provides the predesignated On-Scene Coordinators (OSCs) for the coastal zone and chairs the RRT when it is activated during a coastal zone response. The Coast Guard provides representatives to the RRT when activated for inland spills. In the coastal zone, the Coast Guard will ensure that the NCP is effectively and efficiently implemented with optimum coordination among Federal agencies and will recommend changes in the Plan as necessary. For an inland zone response, the Coast Guard provides technical expertise and resources relative to environmental protection and mitigation during periods of RRT activation. The Coast Guard offers expertise in marine environmental protection, port safety and security, marine law enforcement, ship navigation and construction, and the manning, operation and safety of vessels and marine facilities. For the purpose of planned RRT meetings, the Coast Guard will serve as Co-Chairman with the EPA.

b. The Coast Guard maintains facilities, vessels, aircraft and vehicles which can be used for command, control, and surveillance of pollution incidents occurring in coastal areas. The USCG also maintains special forces and teams including the staff of the National Response Center (NRC), the National Strike Force (NSF), the OSC Emergency Task Force (ETF), the Coast Guard District Staff Emergency Task Group (ETG), and the Public Information Assist Team (PIAT). See Section 300 for further discussion of these special forces.

12. The Environmental Protection Agency (EPA).

a. The EPA provides predesignated On-Scene Coordinators for the inland zone and chairs the RRT during an inland spill response. EPA provides a representative to the RRT when activated for coastal spills. In the Inland zone, EPA will ensure that the NCP is effectively and efficiently implemented with optimum coordination among Federal agencies and will recommend changes in the Plan as necessary. During a coastal zone response, EPA provides technical expertise and resources relative to environmental protection and mitigation during periods of RRT activation. For the purpose of planned RRT meetings, EPA will serve as Co-Chairman with the Coast Guard.

b. The Alaska Operations Office, Anchorage (AOO), has no clean-up or containment equipment for use should an incident occur. In a major inland spill situation, manpower and equipment will be obtained from commercial contractors, state, Federal, military, industry, public municipalities and local contractors on an availability basis.

c. EPA resources available through the Alaska Operations Office are:

(1) Sample analysis performed by the Regional EPA laboratory, Seattle, Washington or at commercial laboratories in Alaska.

(2) Environmental effects monitoring and advice to the OSC on the use of chemical dispersants. EPA will coordinate scientific interests for on-scene research and provide lab facilities.

(3) Aerial photographic over flights for inland spills: EPA has pre-established arrangements for rapid acquisition of commercial aircraft for aerial photographic services and for rapid processing of the resultant film.

(4) Oil/Hazardous Substance disposal sites: The EPA Region X office maintains necessary liaison with state and local governments to assist the OSC in identifying suitable disposal sites for oil/hazardous substances recovered during a spill response.

(5) EPA maintains special forces to assist the OSC including the Environmental Response Team (ERT) based in Edison, New Jersey, and the Technical Assistance Team (TAT) available from Seattle, Washington. The Oil and Hazardous Materials Technical Assistance Data System (OHMTADS) is accessible by EPA. See section 307 of this plan for further discussion of these special forces.

13. The <u>Federal Emergency Management Agency (FEMA)</u>.

a. FEMA monitors the status of pollution emergencies and would evaluate a request for a major disaster declaration if received from the Governor of Alaska pursuant to the Disaster Relief Act of 1974, as amended. If the President declares that a pollution emergency constitutes a major disaster, the Director of FEMA will coordinate and direct the Federal response.

b. FEMA is delegated responsibility under CERCLA and Executive Order 12316 for temporary housing and permanent relocation of residents, businesses and community facilities as a result of hazardous material incidents covered by CERCLA.

E. Role and Responsibilities of the State of Alaska.

1. The Governor of Alaska has designated the Alaska Department of Environmental Conservation as the state RRT representative. ADEC also represents and coordinates the RRT involvement of various other state, county, and municipal organizations.

2. ADEC provides the State On-Scene Coordinator (SOSC) and State Spill Response Team (SSRT) for oil or hazardous substances incidents in accordance with Alaska Oil and Hazardous Substances Pollution Contingency Plan as authorized by the Alaska Oil Pollution and Other Hazardous Substances Control Act.

3. ADEC has various functions, capabilities and resources both before and during a pollution incident. They include:

a. maintaining and making proper disbursements from the Oil Spill Expense Reserve.

b. maintaining a current listing of available containment and cleanup equipment, providing on-scene monitoring of all discharge cleanup activities for which ADEC is designated as the lead State Agency, coordinating technical expertise concerning the biological impact of a probable or existing discharge.

c. determining and approving the locations to be used as pollutant disposal sites.

d. pre-planning and concurring on the use of dispersants for the State of Alaska, along with EPA. (See Annex X concerning Dispersant Use.)

e. providing notification of a hazardous material incident to the appropriate State, local and Federal agencies.

f. providing a Public Information Officer, in coordination with Office of the Governor, and

g. arranging for emergency hazardous substance response with private contractors.

h. providing population data for all locations throughout the State of Alaska through the Alaska State Demographer: Dr. Greg Williams, (907)465-4500.

F. The planning and preparedness functions of the Regional Response Team are outlined below:

1. Maintain a continuing review of regional pollution emergency response operations and equipment readiness to insure adequacy of regional planning and coordination for combating discharges of oil and hazardous substances.

2. Develop procedures to promote the coordination of Federal, State and local governments, and industry groups and private agencies to respond to pollution incidents.

3. Provide information to the NRT on research requirements.

4. Maintain a readiness posture to respond to significant discharges of oil or other hazardous substances.

5. Recommend revisions of the National Plan to the NRT on the basis of observations of response operations.

G. The response and coordination functions of the RRT are outlined as follows:

1. Respond whenever the RRT is activated. The degree of response and therefore the extent of RRT activity will depend on the particular situation.

2. Monitor and evaluate reports generated by the OSC ensuring their completeness. Based on this evaluation, the RRT may recommend courses of action in combating a discharge.

3. Assist the OSC in acquiring and employing response resources from Federal, State, and Local governments and private agencies.

4. Coordinate all Federal public information activities with the OSC and act as the focal point for information transfer between the OSC and the NRT, so as to minimize or prevent dissemination of spurious or incomplete information. Public information actions are discussed in Annex VI of this plan.

5. Submit POLREPs to the NRT as determined necessary by the appropriate Co-chairman.

303. RRT Activation.

A. The RRT comprises members of many agencies who must, with no prior notice, be capable of responding to an incident and call out personnel and equipment from their agency in an expeditious manner. The key to successful response actions is prompt activation and implementation of this Plan. The appropriate RRT Co-Chairman will activate whenever one of the following situations exists:

1. A major or potential major discharge or release (activation is automatic);

2. Any pollution emergency when the OSC/RPM or any member of the RRT makes a request to the RRT Co-Chairman;

3. At any time when determined by either Co-Chairman.

B. The RRT may be activated by any means of communications, but will normally be done by telephone to the persons designated in Annex II of this Plan. The activation call will specify the time of RRT activation, the meeting place if assembly is planned, and as much about the incident and the requirements to be placed on the particular agency as are known. (A full membership activation will normally be called whenever a major incident occurs.) A limited membership activation may be called by either co-chairman, whenever it is apparent that the service of only selected members is needed.

C. The Co-Chairman will determine if assembly of the RRT is advantageous or whether telephone activation and electronic mail is sufficient to respond to the incident.

D. It is anticipated that lesser incidents for which a limited membership activation has been called will normally be handled by telephone or electronic mail. Activated members will operate from their home or business location and will coordinate their agency's on-scene staff tasks and RRT staff tasks from that point. The Regional Response Center (RRC) will be staffed by USCG or EPA personnel and a contact system will be maintained with each activated member. Members will call into the RRC whenever the member needs to discuss matters with the Co-chairman or whenever the member is about to make a change of location and telephone contact number.

E. Assembly of the RRT will normally occur whenever a major incident occurs; all members are activated; extensive briefings are necessary for members; or whenever a drill activation for training occurs. The assembly of the RRT will normally occur at the RRC or alternate RRC site indicated in section 304 below. Members should be prepared to operate from the RRC. Therefore, members are encouraged to provide all necessary contact lists, agency phone books, technical manuals, etc., necessary to implement the appropriate tasks assigned the agency. In prolonged RRT activations, it is anticipated that members will return to their homes or place of business after the RRT assembly briefing to continue their RRT tasks and attend future RRT meetings as prescribed by the Co-Chairman.

F. Deactivation of the RRT will occur after mutual agreement by the senior USCG and EPA members. Deactivation will normally be by telephone notification unless the RRT is assembled.

304. Regional Response Center.

A. The Regional Response Center is the regional coordinating site for notification, communication, and inter-agency coordination during a pollution incident. The primary Regional Response Center is located within the Operations Center of the Commander, Seventeenth Coast Guard District and is staffed around - the - clock. It may be contacted at (FTS) 759-7340 or (907) 586-7340. The alternate Regional Response Center is located in the EPA, Alaska Operations office at Anchorage, and is staffed on an as needed basis. It may be contacted at (907) 271-5083 or (206)442-1263 after normal working hours.

B. Additional alternate sites for the Regional Response Center may be designated at the discretion of the appropriate Co-Chairman when needed.

305. RRT Communications.

A. RRT activation will normally be conducted by the appropriate RRT Co-Chairman by the most rapid means available, normally the telephone. Upon activation, RRT members will automatically begin receiving copies of all message traffic from the OSC to the Regional Response Center and from the Regional Response Center to the National Response Center.

B. Routine Communications will be performed by telephone and use of the electronic mail system (See Tab A of Annex V for a description of the E-mail system). General messages can be transmitted using the "Mail" function. Information concerning spill reports will be transmitted to RRT members, using the "RRT" function.

306. On-Scene Coordination.

A. As the single Federal official responsible for ensuring proper pollution response and enforcement, the OSC is the most important component in the national response organization. Federal on-scene coordination during a response is accomplished through the OSC, who provides reports to and receives advice from the RRT. The U.S. Coast Guard designates the OSC for discharges of oil or release of hazardous substances in the coastal zone; EPA designates the OSC for inland response operations dealing with discharges of oil or hazardous substance releases. If the incident involves a release from a chemical waste site, EPA will provide the OSC. DOD will furnish the OSC for hazardous substance releases from DOD facilities or vessels.

The OSC/RPM directs Federal Fund-financed response efforts and coordinates all other Federal efforts at the scene of a release or discharge. Should the circumstances indicate, the OSC/RPM can request support from special forces with expertise in containment and cleanup, environmental protection, and public affairs. The OSC/RPM:

a. shall collect pertinent facts about the discharge or release such as its source; potentially responsible party; nature, amount, and location of the material; and potential impact upon the environment and human health, welfare and safety;

b. shall promptly advise the appropriate State agency;

c. should notify the affected land managing agency and trustees of natural resources, as promptly as possible;

d. shall address worker health and safety at the response scene;

e. shall direct response operations as described in Subparts E and F of the NCP;

f. should consult regularly with the incident-specific RRT when it has been activated;

g. shall evaluate incoming information and immediately advise FEMA of potential major disaster situations and the HHS representative when a possible public health emergency exists;

h. should consult with DOI and DOC/NOAA representatives if a discharge or release may adversely affect any endangered or threatened species, or result in destruction or adverse modification of the habitat of such species;

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

RECEIVED

August 24, 1989

Environmental ...

The Honorable Samuel Skinner
Secretary
Department of Transportation
Room 10200
400 Seventh Street, SW
Washington, DC 20590

Dear Mr. Secretary:

The grounding of the T/V Exxon Valdez and resulting disastrous oil spill demonstrates the need for improving navigational aids and tracking systems, and assessing conditions under which crude oil tanker and tank barge traffic proceeds in Alaskan waters.

The State of Alaska has taken steps to improve navigation safety by oil tankers and tank barges in Prince William Sound. We are writing now not only to inform you of these initiatives, but also to ask your assistance in seeking and implementing further safeguards in Prince William Sound and in Cook Inlet.

We have identified a suite of safety measures and proposed navigational aids that I think would go a long way toward preventing another occurrence like the grounding of the T/V Exxon Valdez. They include those we can and have implemented ourselves, some that require legislative action by Congress, and several within the regulatory authority of the Coast Guard but which may require funding.

As one means to improve the safety of tanker traffic, the Alaska Department of Environmental Conservation has issued an emergency order to Alyeska Pipeline Service Company. This order requires, among other things, that two tugs accompany all outbound tankers to Hinchinbrook Entrance, the entrance to Prince William Sound, and that a pilot licensed for Prince William Sound be aboard the bridge of any cargo-laden tanker between the Valdez Marine Terminal and Seal Rocks. As further provided in the Order, Alyeska Pipeline Service Company has established an alcohol testing program for command officers of tankers. As directed, Alyeska has enhanced substantially its response and cleanup capability. The State has extended the distance from Valdez in which tankers must have state-licensed pilots on board. Previously, state-licensed pilots left tankers north of Bligh Reef; now they will disembark at a point south of Bligh Island.

These state requirements will help in Prince William Sound. However, we believe that it is important to obtain the increased measure of safety that can be provided by backing up the State's action with federal action in both Prince William Sound and Cook Inlet. While the State has not invoked emergency measures in Cook Inlet, the navigational hazards there are also of concern.

The enclosed list of navigational aids and safety measures includes agency or Congressional actions that the State believes are necessary in the short term to guard against future oil spills in Prince William Sound and Cook Inlet. The list was developed by the Alaska Department of Environmental Conservation after consultation with the state marine pilots' association, and other state agencies. We look forward to your analysis of which actions can be accomplished by your agency in the near future and which require Congressional action.

We offer whatever assistance would help to implement these proposals as soon as possible. Members of my cabinet and I already have lent support to a number of these ideas in testimony before Congressional committees. The State also is working closely with those members and committees that have jurisdiction over these issues and the funding to make them possible. We look forward to working with you on the regulatory items as well.

Thank you for your consideration of these important matters.

Sincerely,

Steve Cowper
Governor

Enclosure

cc: Secretary Robert A. Mosbacher, Sr.
Commissioner Dennis D. Kelso
John W. Katz, Special Counsel
Bob LeResche, State Oil Spill Coordinator

STATE OF ALASKA

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

NAVIGATIONAL AIDS FOR PRINCE WILLIAM SOUND AND COOK INLET TANK VESSEL AND BARGE TRAFFIC

1. Provide increased funding for United State Coast Guard (USCG) Alaska operations to allow implementation of enhanced navigational aids for Prince William Sound and Cook Inlet tanker traffic, improve USCG operations statewide, and provide enhanced training for USCG vessel traffic system personnel.

2. Re-equip the USCG Vessel Traffic System (VTS) in Prince William Sound with more powerful, state-of-the-art radar equipment which will track tankers and sound an alarm should tankers leave designated traffic lanes. Install a similar system in Cook Inlet.

3. Install USCG-operated VTS radar on Naked Island and/or Hinchinbrook Island in order to provide full radar coverage of the tanker traffic lanes and tanker anchorages.

4. Review operations during poor weather conditions to determine whether loaded tanker and tank barge traffic should be restricted during conditions that would hamper oil spill tracking, containment and recovery operations. Install additional weather stations in the Prince William Sound and Cook Inlet areas as needed in order to secure adequate data for forecasting weather conditions (including visibility, wind and sea states) that would preclude oil spill tracking, containment and recovery operations.

5. Install electronic radio beacons (RACON) or lighthouse structures equipped with powerful, long range navigational lights on Bligh Reef and Seal Rocks. Install these same devices on navigational hazards in Cook Inlet.

6. Require that all tankers of any registry transiting Prince Williams Sound at any point between Seal Rocks and the Alyeska Pipeline Service Company Valdez Marine Terminal have aboard a federally licensed pilot to assist in navigation, communications and lookout. Evaluate the pilotage requirements for Cook Inlet tankers and invoke comparable restrictions.

7. Require tankers transiting Prince William Sound and Cook Inlet to fix their positions on the nautical chart or chart overlay of the area at least once every six minutes and retain the chart or overlay with these positions for thirty days for inspection by USCG.

8. Require all tankers of any registry entering and departing Port Valdez to embark and disembark a state-licensed pilot in the vicinity of Bligh Reef at Latitude 60° 49'N, Longitude 147° 01'W. Establish similar requirements for Cook Inlet.

9. Require two tug boats to accompany all outbound tankers to Hinchinbrook Entrance and to accompany any inbound tanker with crude oil cargo from Hinchinbrook Entrance to the Alyeska Valdez Marine Terminal.

10. Require direct radio contact between Alyeska's Valdez Marine Terminal Operations Center and the bridge of incoming and outgoing tankers, accompanying tugs, and Alyeska's oil spill response vessels while incoming or outgoing tankers are located at any point between the Valdez Marine Terminal and Seal Rocks at the Hinchinbrook Entrance. Require Alyeska to record all radio transmissions and preserve each recording for a period of at least thirty days for submission to ADEC and the USCG upon request. Require terminal--tanker radio contact in Cook Inlet.

11. Require each tanker, accompanying tug boats, and oil spill response vessels to notify the terminal <u>immediately</u> by radio transmission if an incident occurs or if there is any indication of a problem which threatens an outbound or inbound tanker or other tank vessel, or its cargo. Incident(s) include, but are not limited to: (a) any mechanical problem with the vessel that might affect the power or steering of the vessel; (b) the discovery of any hull damage and/or compartment flooding; or (c) any collision that jeopardizes the seaworthiness of the vessel, including any collision with an iceberg that jeopardizes the seaworthiness of the vessel.

12. Require masters of tanker vessels to reduce speed and to maneuver through ice while remaining within the designated traffic lanes or to delay sailing from the terminal if ice conditions prevent them from maneuvering at a slower rate of speed while maintaining their vessels within the designated traffic lanes during transit through the ice.

13. Require mandatory random drug and alcohol testing for all persons in command of tankers and tank barges, and prohibit the use of drugs or alcohol by such persons within twelve hours of their boarding of any such vessel.

14. Forbid the use of Montague Straits by tankers or tank barges not making fuel deliveries for use by local communities.

15. Evaluate the size and overall adequacy of ship complements aboard tanker vessels and require increased training and experience for personnel on the bridge of tanker vessels.

FINAL REPORT

AN ASSESSMENT OF TANKER TRANSPORTATION SYSTEMS IN COOK INLET AND PRINCE WILLIAM SOUND

PREPARED FOR:

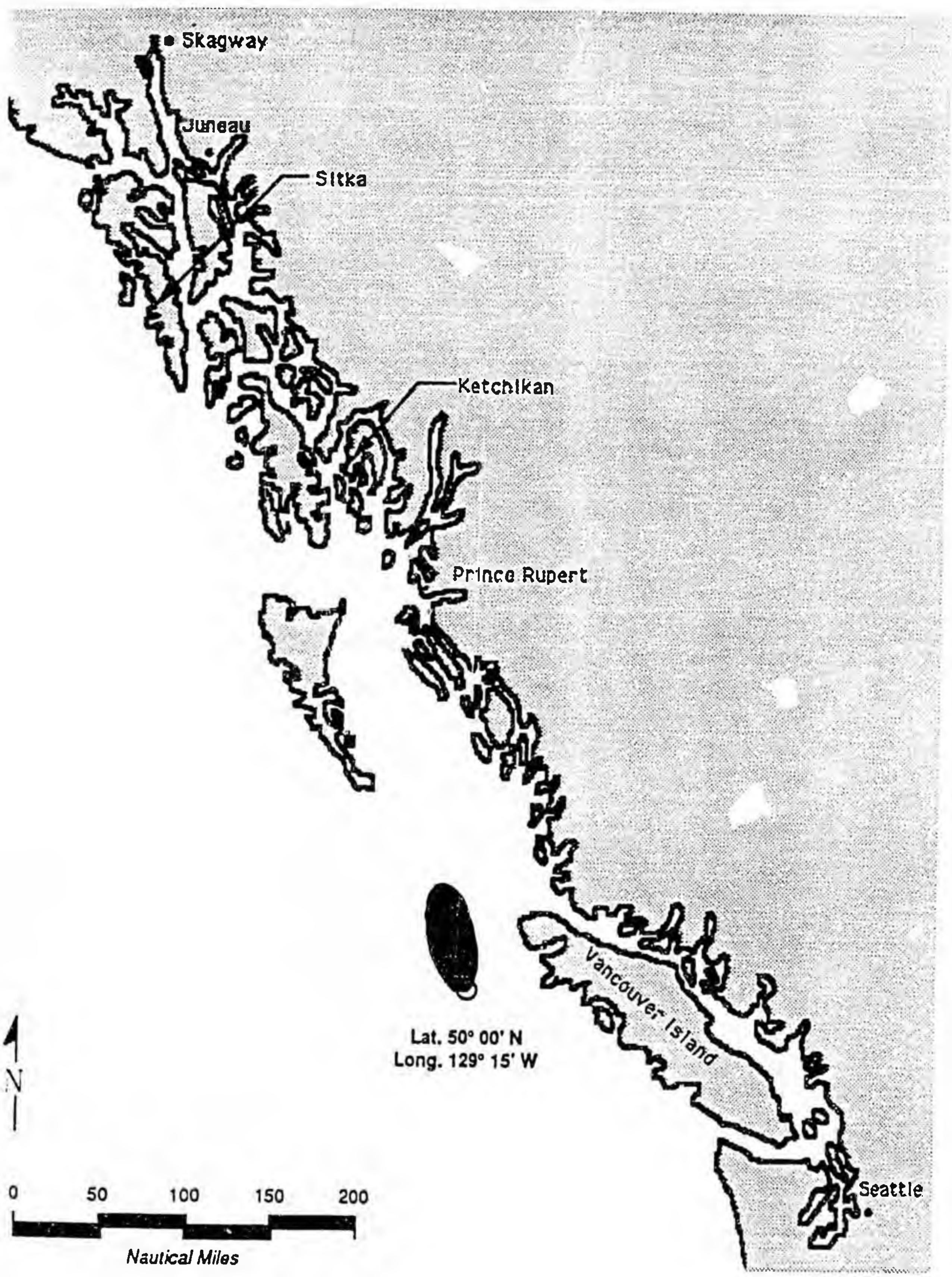
ALASKA OIL SPILL COMMISSION
707 "A" STREET, SUITE 202
ANCHORAGE, ALASKA 99501

PREPARED BY:

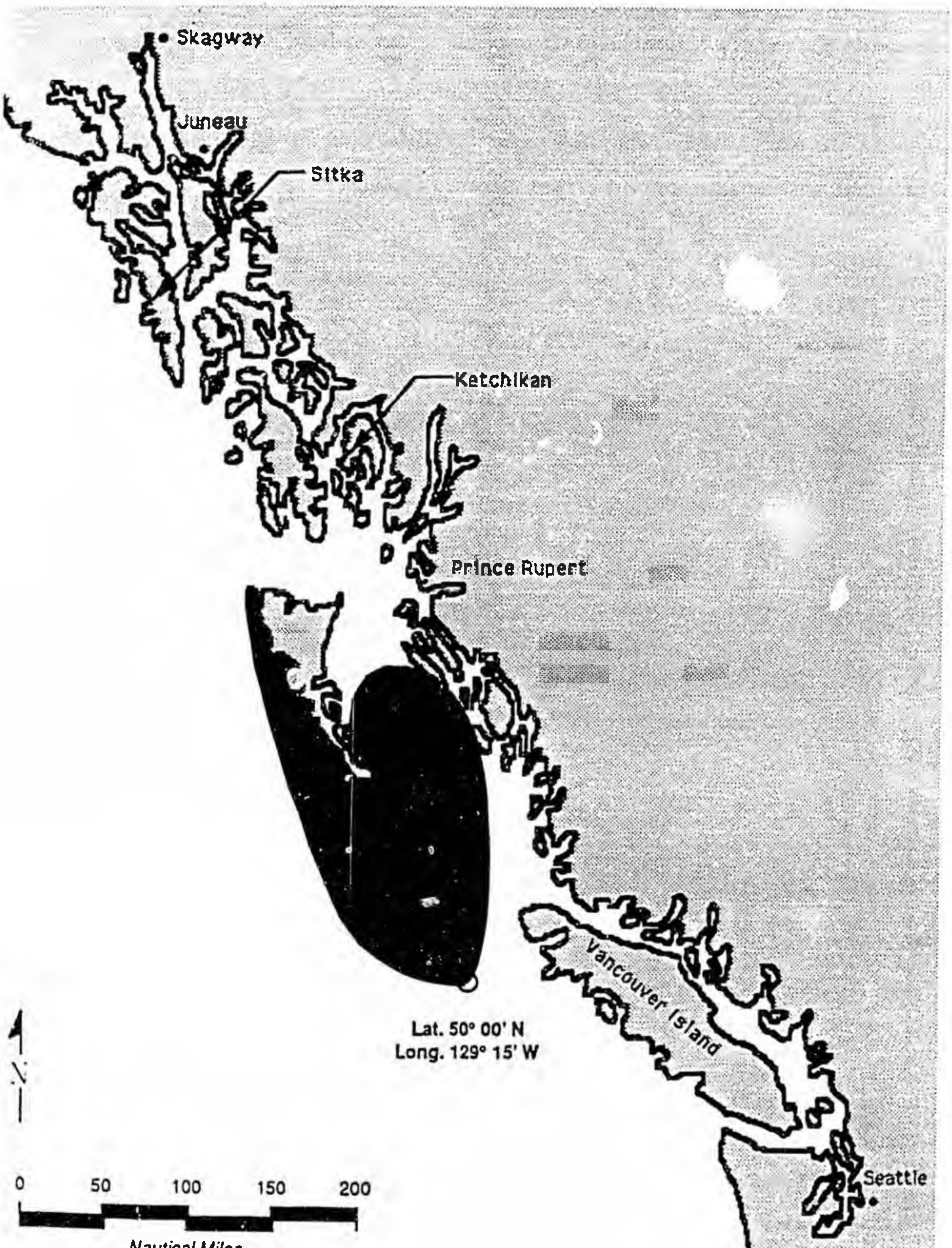
ENGINEERING COMPUTER OPTECNOMICS, INC. (ECO)
1036 CAPE ST. CLAIRE CENTER
ANNAPOLIS, MARYLAND 21401

DECEMBER 8, 1989

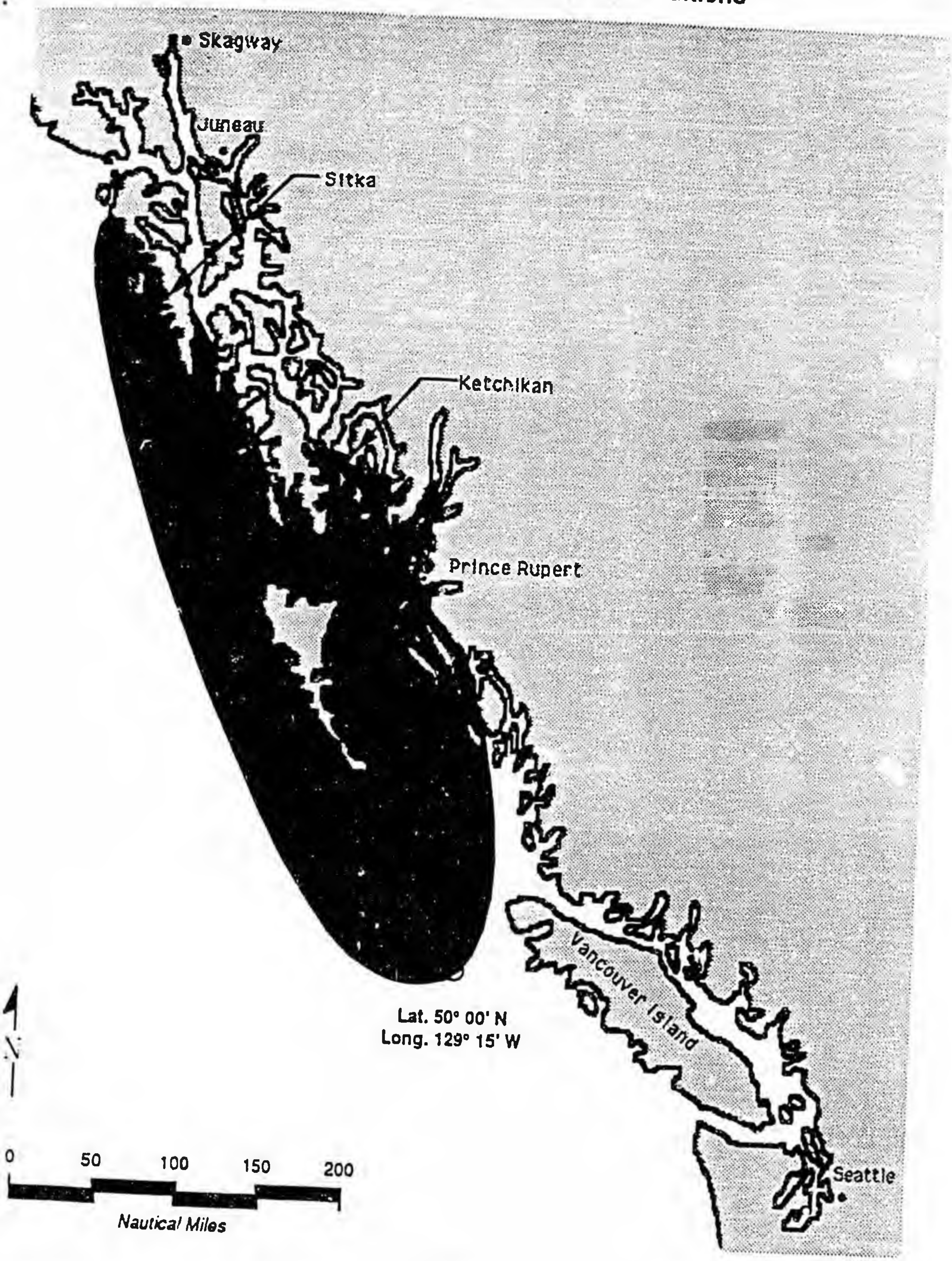
Offshore Spill Site 1 - 24 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



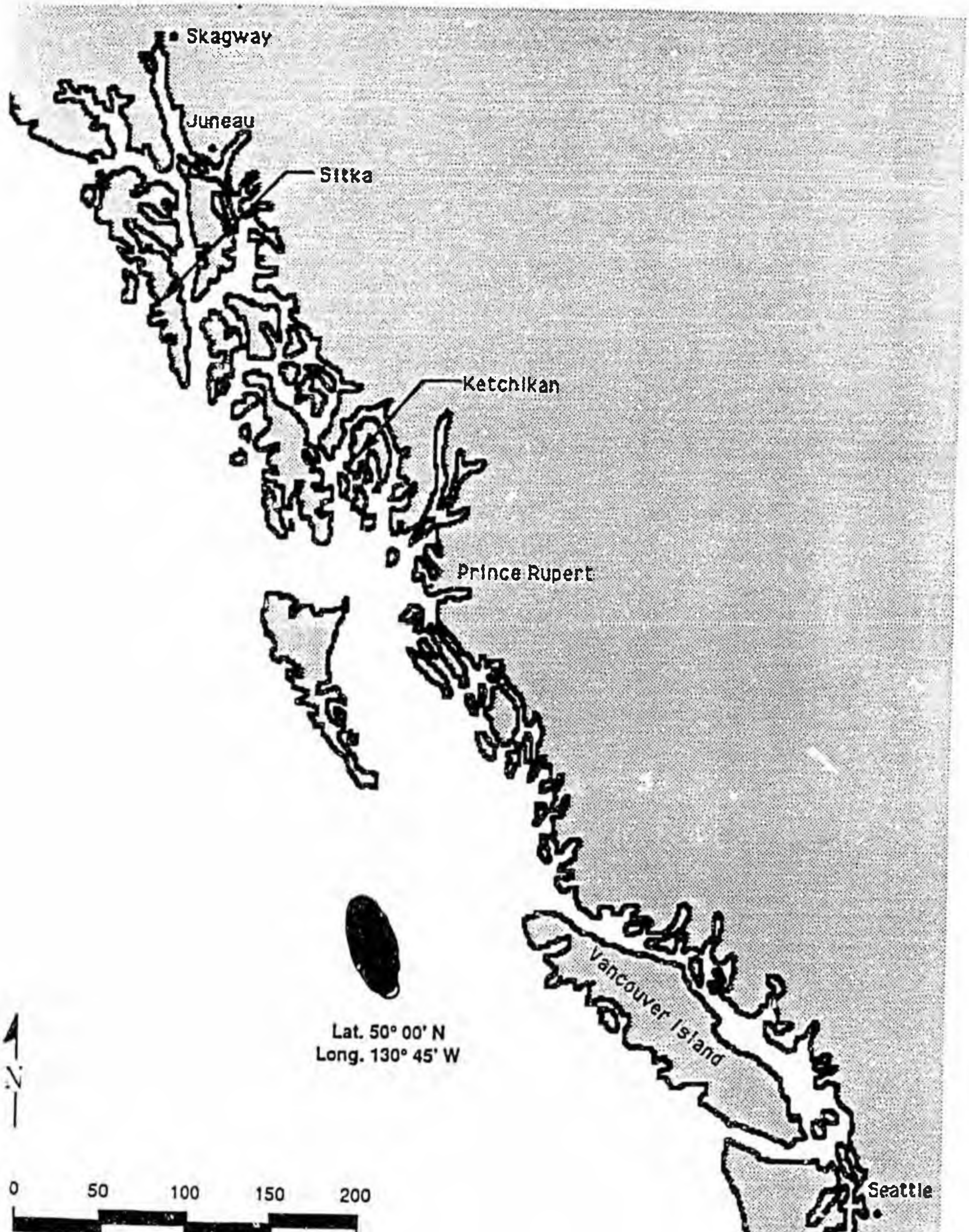
Offshore Spill Site 1 - 168 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



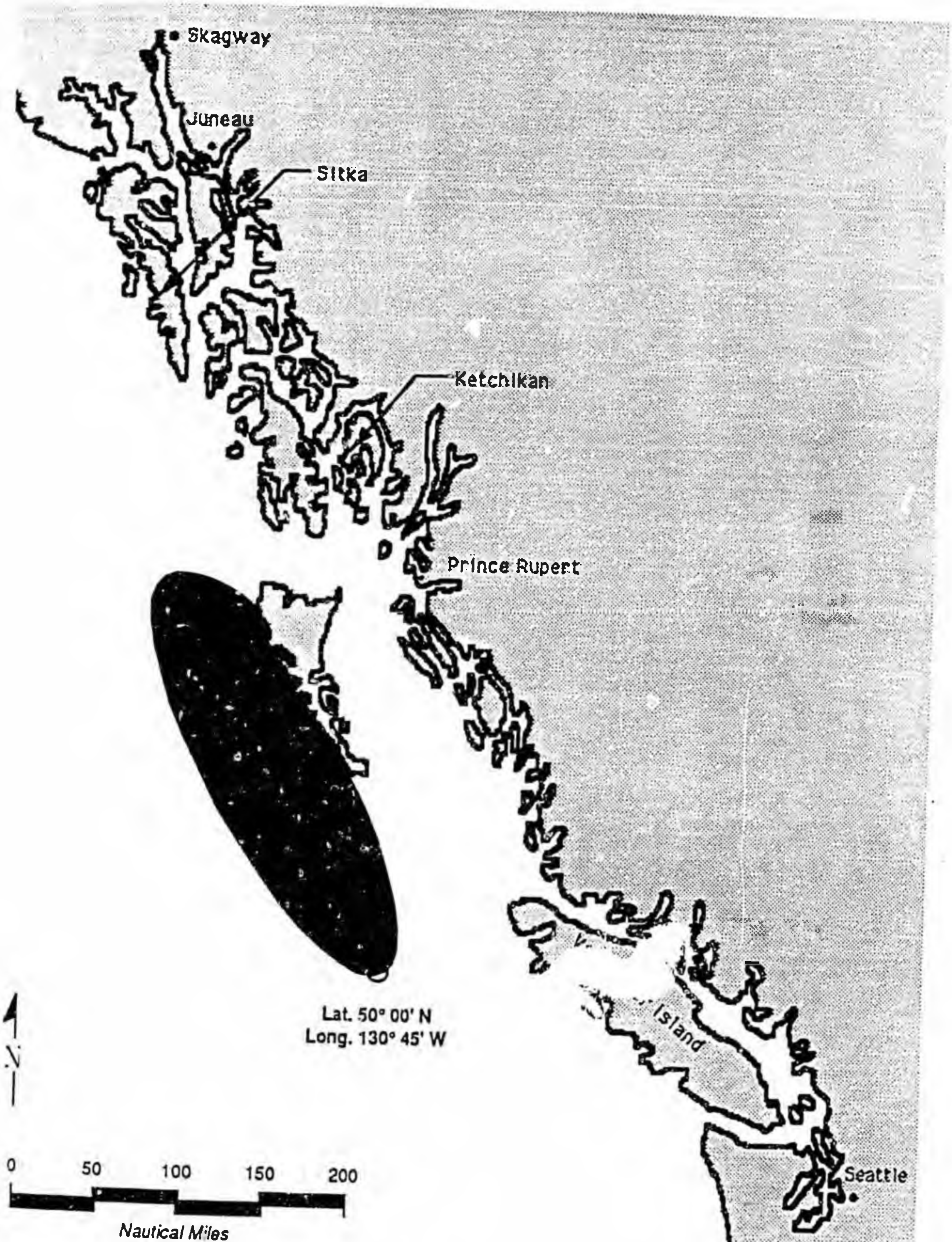
Offshore Spill Site 1 - 336 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



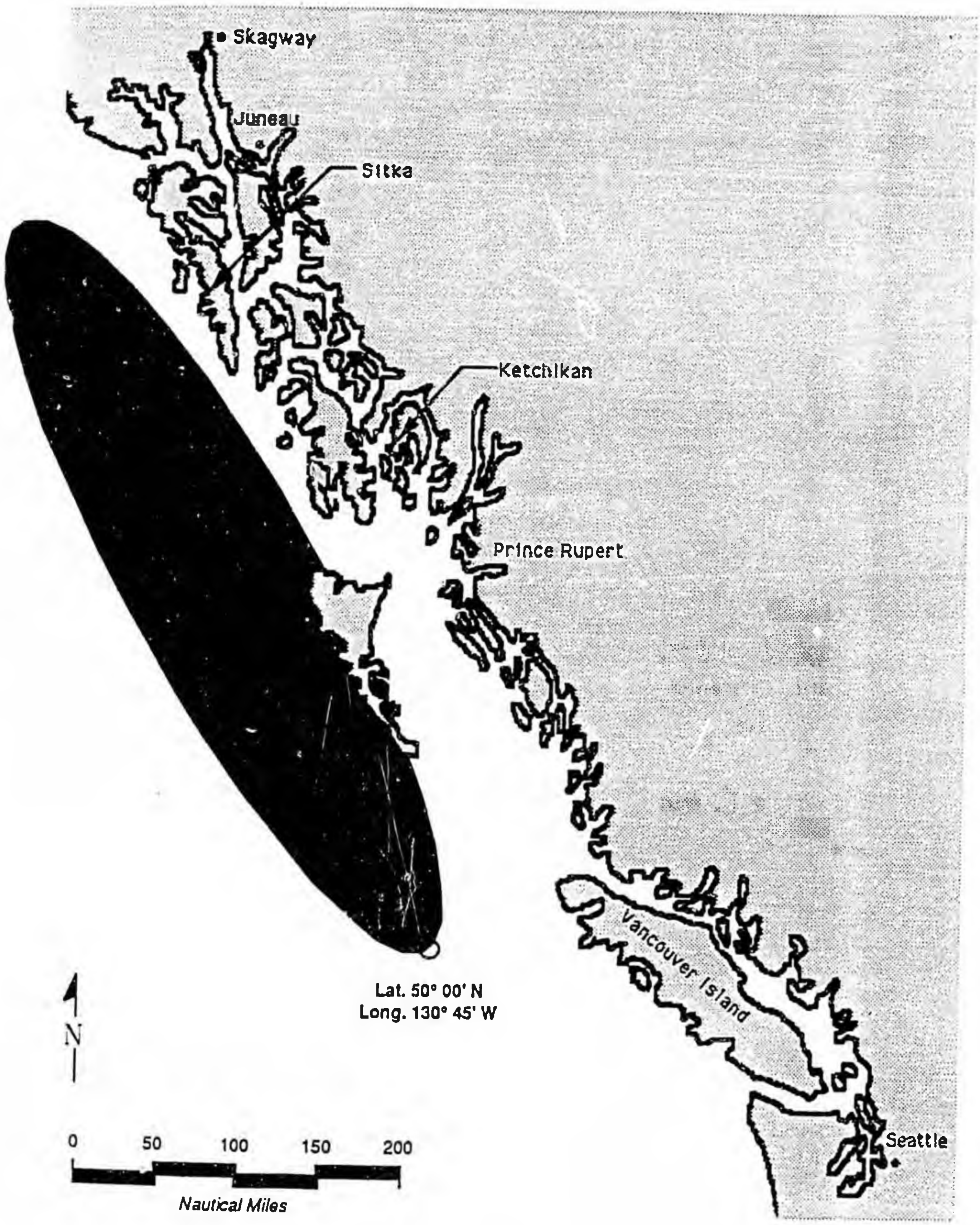
Offshore Spill Site 2 - 24 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



Offshore Spill Site 2 - 168 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



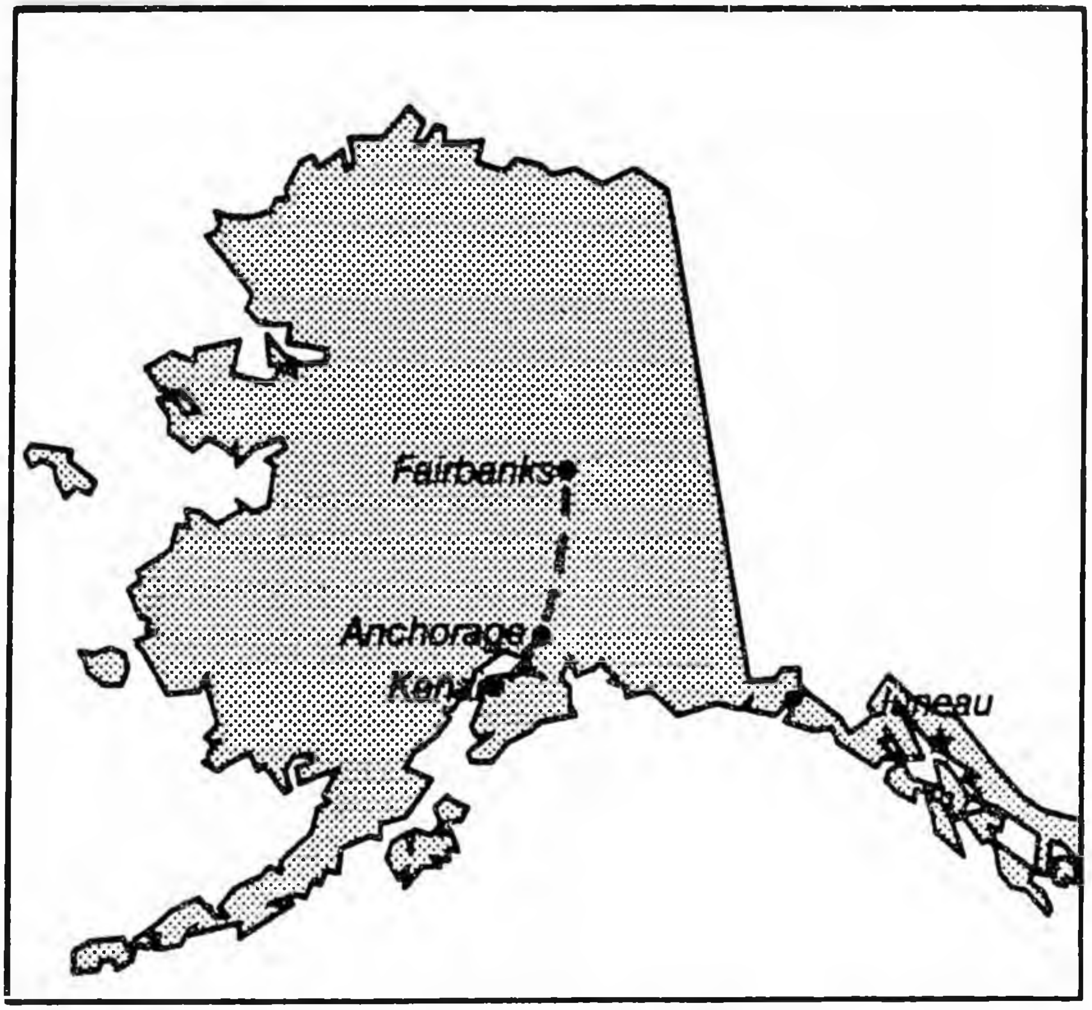
Offshore Spill Site 2 - 336 Hours After Spill
Spill Size = 75,000,000 Gallons
Typical Winter Wind And Current Conditions



OVERVIEW - 138KV TRANSMISSION LINE

ECONOMIC FEASIBILITY
of the proposed
138 KV TRANSMISSION LINES IN THE RAILBELT

prepared for
Railbelt Electric Utilities



prepared by

DECISION FOCUS INCORPORATED

December 1989

ECONOMIC FEASIBILITY OF THE PROPOSED 138 KV TRANSMISSION LINES IN THE RAILBELT

Prepared for

Railbelt Electric Utilities

Prepared by

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Decision Focus Incorporated
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Los Altos, California 94022
DFI #1886

December 21, 1989

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CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

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Section 1

INTRODUCTION

1.1 BACKGROUND

The Reconnaissance Study[1] prepared by Decision Focus Incorporated for the Alaska Power Authority (now Alaska Energy Authority) presented the costs and benefits of several intertie proposals suggested for the Railbelt. The study concluded that a new 230 KV line between Kenai and Anchorage, and a full upgrade of the Anchorage-Fairbanks line are not cost effective.

After the completion of the Reconnaissance Study, the Railbelt electric utilities proposed new downsized (138 KV) transmission lines between Kenai and Anchorage (southern line) and between Healy and Fairbanks (northern line). The northern line proposal would also include a limited upgrade of the Anchorage-Fairbanks line.

1.2 OBJECTIVE

The objective of this study is to assess the economic feasibility of the proposed Healy-Fairbanks 138 KV new intertie and the proposed Kenai-Anchorage 138 KV new intertie. The economic feasibility of the limited upgrade of the Anchorage-Fairbanks line is also evaluated. The purpose of this report is to present the results of the study.

1.3 REPORT ORGANIZATION

This report is organized similar to the Reconnaissance Study to facilitate the comparison between the costs and benefits of the proposed 138 KV interties presented in this study and the other alternatives (e.g., the 230 KV Kenai-Anchorage proposal and the full upgrade of the Anchorage-Fairbanks line) described in the Reconnaissance Study.

1. "Railbelt Intertie Reconnaissance Study, Benefits/Cost Analysis," prepared by Decision Focus Incorporated, for the Alaska Power Authority, June, 1989.

1.4 STUDY OVERVIEW

The assessment of the proposed transmission lines is focused on a comparison of their expected economic costs and benefits. Most inputs to this economic analysis such as fuel price and electric demand forecasts, were established by the Alaska Power Authority (now Alaska Energy Authority) and are reported in the Reconnaissance Study. New evidence and more detailed analysis of issues necessitated the update of several input assumptions. All changes and new estimates are documented in this report.

Several categories of possible benefit have been evaluated for the intertie proposals. These primary benefit categories include:

1. *Reliability.* Intertie projects can affect system reliability and a value can be attached to estimated improvements. Reliability can be measured by the number, duration, and magnitude of customer outages. Reliability benefits are explored in Section 4.

2. *Economy Energy Transfer.* Savings are realized when an intertie project allows more displacement of higher cost energy in one area with lower cost energy imported from another area. This is presented in Section 5.

3. *Transmission Efficiency.* New, improved interties can produce savings to the extent that transmission losses are reduced. This is also presented in Section 5.

4. *State Revenue.* New, improved interties can lead to increased substitution of gas for oil and therefore to increased state revenues from increased gas royalty and severance taxes. This is also presented in Section 5.

5. *Capacity Sharing.* An intertie project may allow two or more areas to share capacity and, as a result, an increment of future investment in plant capacity could be deferred or avoided. This is presented in Section 6.

6. *Operating Reserve Sharing.* Operating reserves are typically maintained to help avoid customer outages. An intertie project could allow two or more areas to share operating reserves and therefore reduce operating costs. This is presented in Section 7.

1.5 SUMMARY OF FINDINGS

Table 1-1 shows the expected[2] costs and benefits for each of the three alternatives. Both the total and incremental (incremental over the limited upgrade of the Anchorage-Fairbanks line) costs and benefits of the Healy-Fairbanks intertie are presented.[3]

Table 1-1

RAILBELT ALTERNATIVES: COSTS AND BENEFITS

	Estimated Cost[a] ($1990 million)	Estimated Benefits[b] ($1990 million)	Benefit to Cost Ratio
New Kenai-Anchorage Intertie	74 to 86[c]	114 to 131	1.3 to 1.8
Limited Upgrade of Anchorage-Fairbanks Intertie	10	46	4.4
Healy-Fairbanks Northern Intertie			
• Total	64	106	1.6
• Incremental[d]	54	60	1.1

Notes:

a. Includes both capital and O&M costs
b. Present value of total benefits between 1994 and 2033 for the Kenai-Anchorage line and between 1994 and 2043 for the Anchorage-Fairbanks upgrade and Healy-Fairbanks line.
c. Includes replacement cost of submarine cable after 20 years of service.
d. Incremental over the limited upgrade of the Anchorage-Fairbanks line.

Figures 1-1 and 1-2 show the present values of net benefits and the benefit to cost ratios for the Kenai-Anchorage new intertie. Figures 1-3 and 1-4 show the present values of net benefits and the benefit to cost ratios for the limited upgrade of the Anchorage-Fairbanks new intertie. Figures 1-7 and 1-8 show the incremental present values of net benefits and the incremental benefit to cost ratios for the new Healy-Fairbanks intertie.

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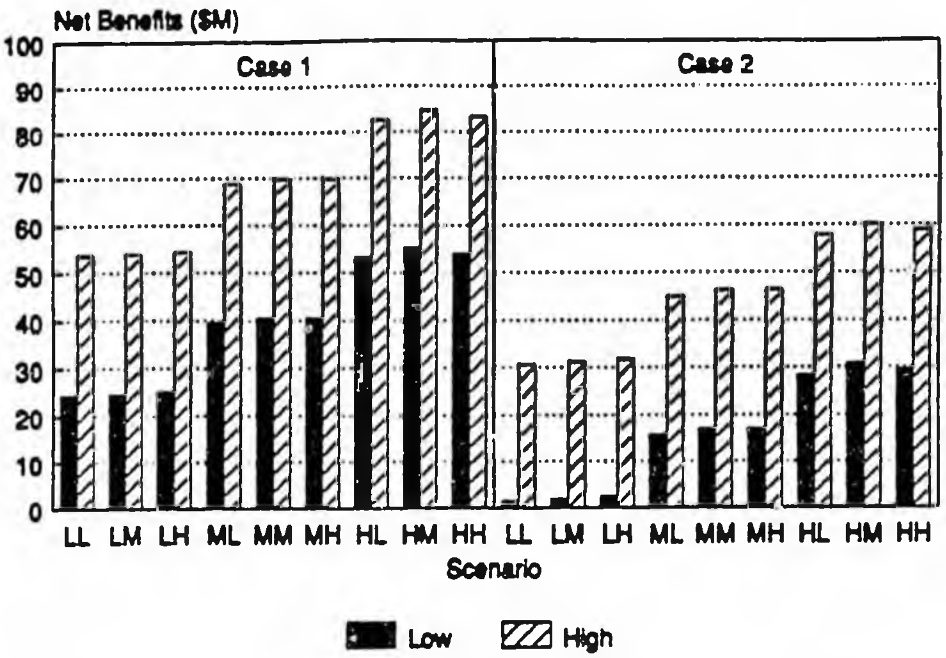
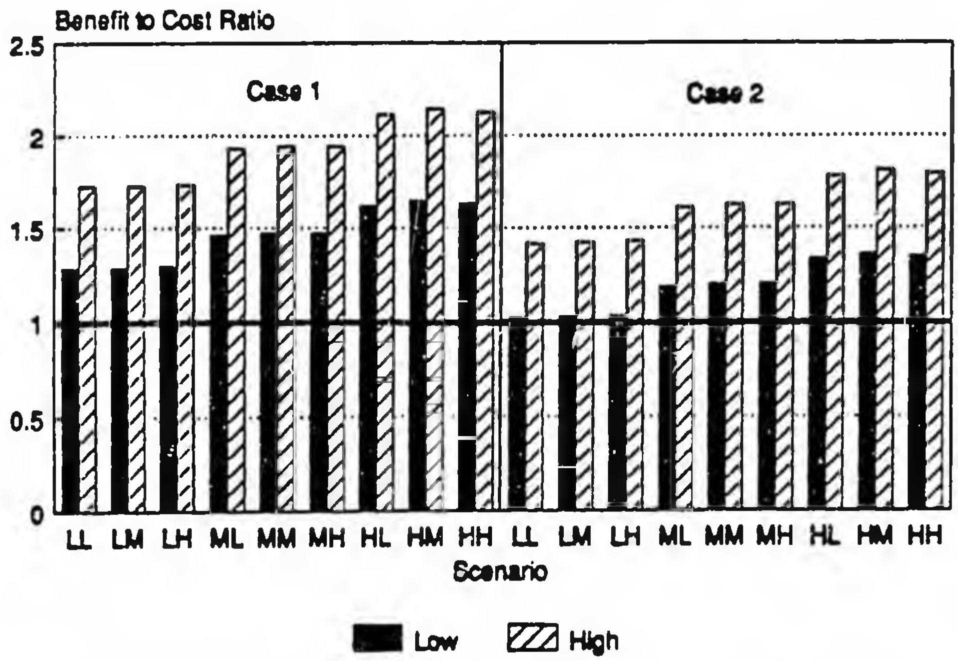
2. Unless otherwise noted, "expected" values are calculated for all scenarios assuming all scenarios have same probability.

3. Unless otherwise noted, these and all other costs and benefits are presented in terms of 1990 dollars.



LL Low Fuel/Low Load	ML Middle Fuel/Low Load	HL High Fuel/Low Load
LM Low Fuel/Middle Load	MM Middle Fuel/Middle Load	HM High Fuel/Middle Load
LH Low Fuel/High Load	MH Middle Fuel/High Load	HH High Fuel/High Load

Figure 1-1. New Kenai-Anchorage Intertie: Net Benefits



LL Low Fuel/Low Load	ML Middle Fuel/Low Load	HL High Fuel/Low Load
LM Low Fuel/Middle Load	MM Middle Fuel/Middle Load	HM High Fuel/Middle Load
LH Low Fuel/High Load	MH Middle Fuel/High Load	HH High Fuel/High Load

Figure 1-2. New Kenai-Anchorage Intertie: Benefit to Cost Ratios

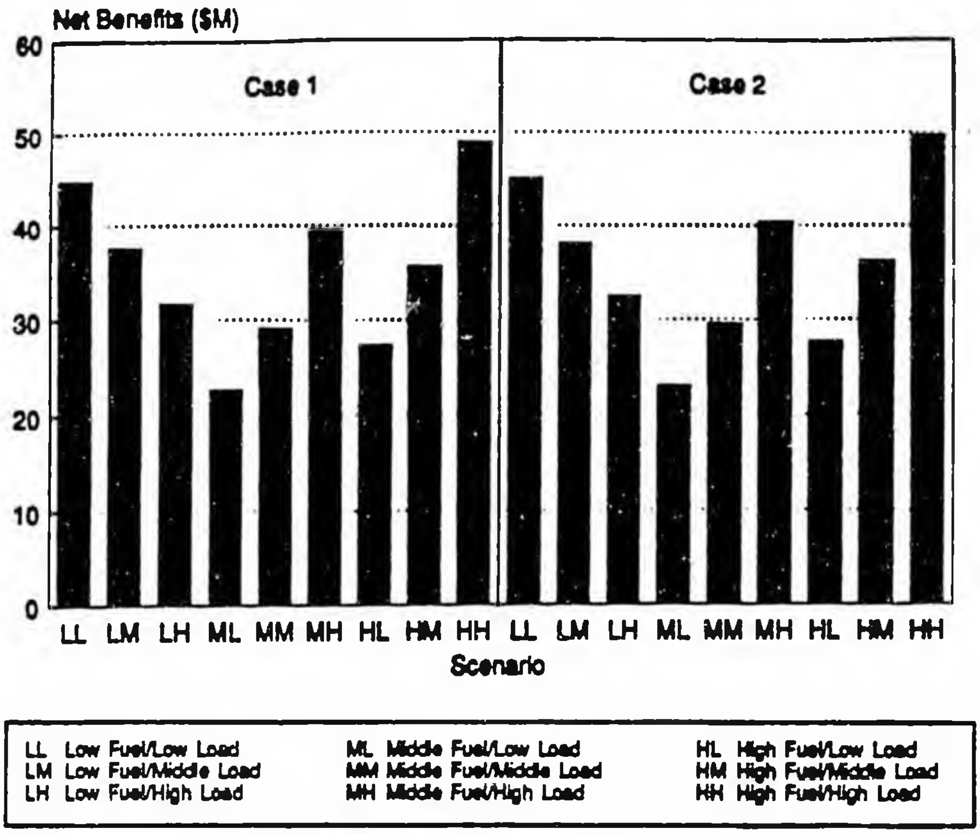


Figure 1-3. Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits

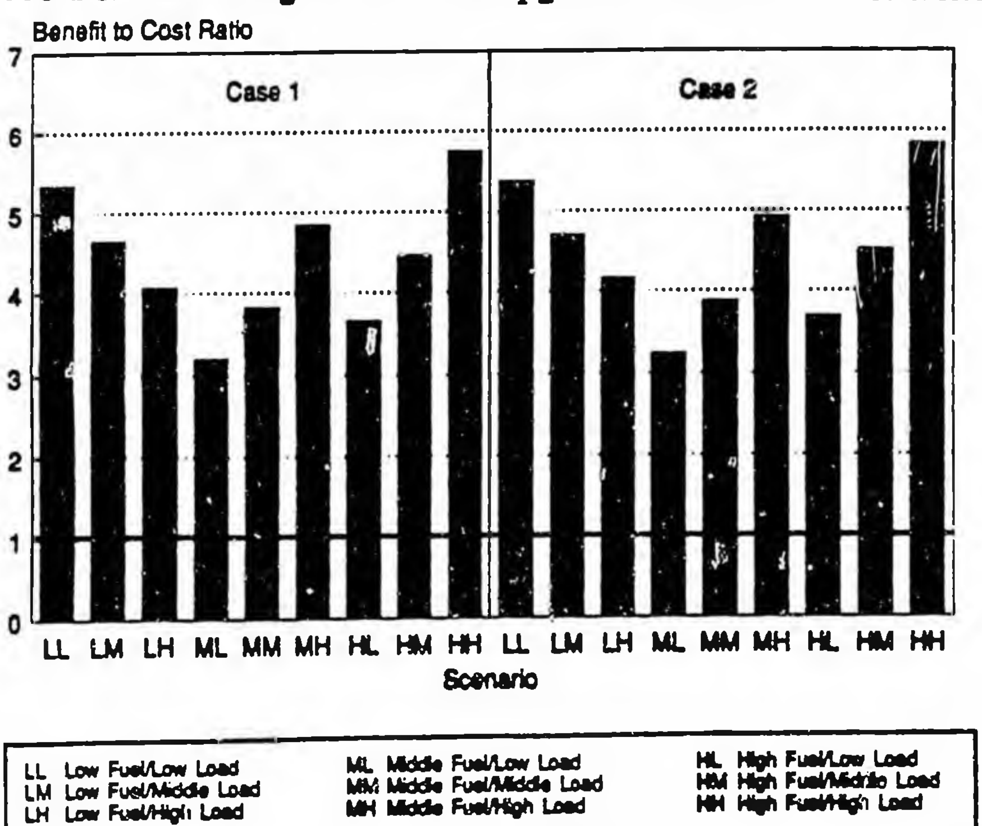


Figure 1-4. Anchorage-Fairbanks Upgrade to 100 MW: Benefit to Cost Ratios

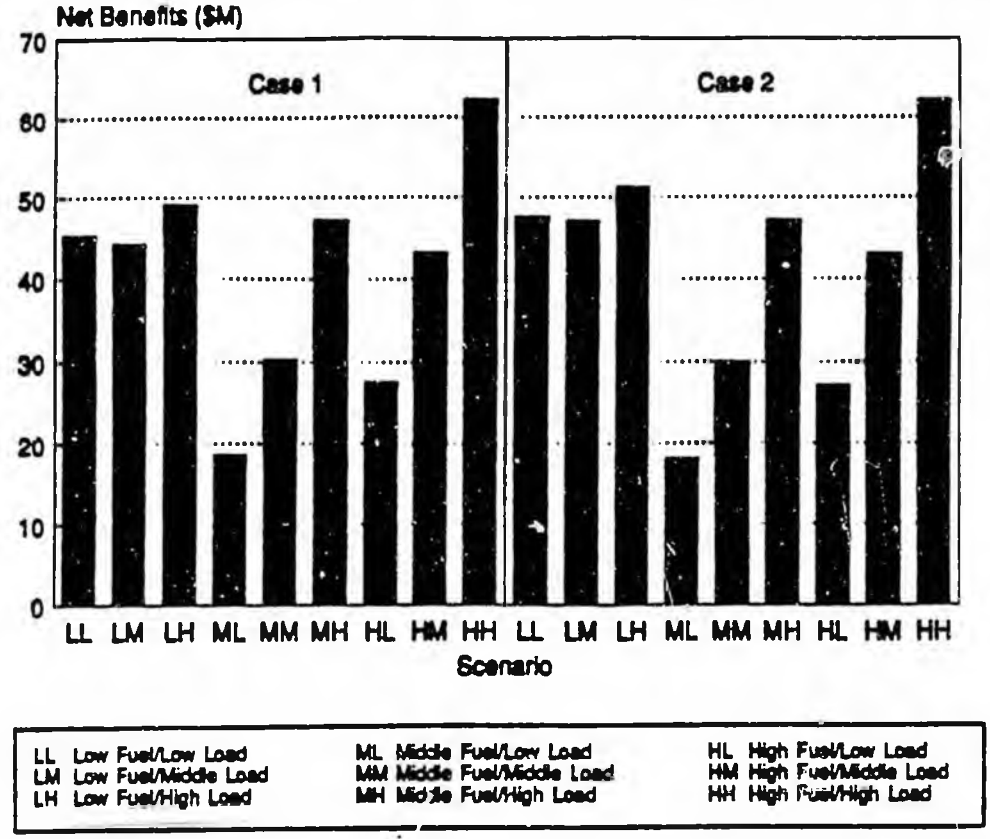


Figure 1-5. Healy-Fairbanks Northern Intertie: Net Benefits

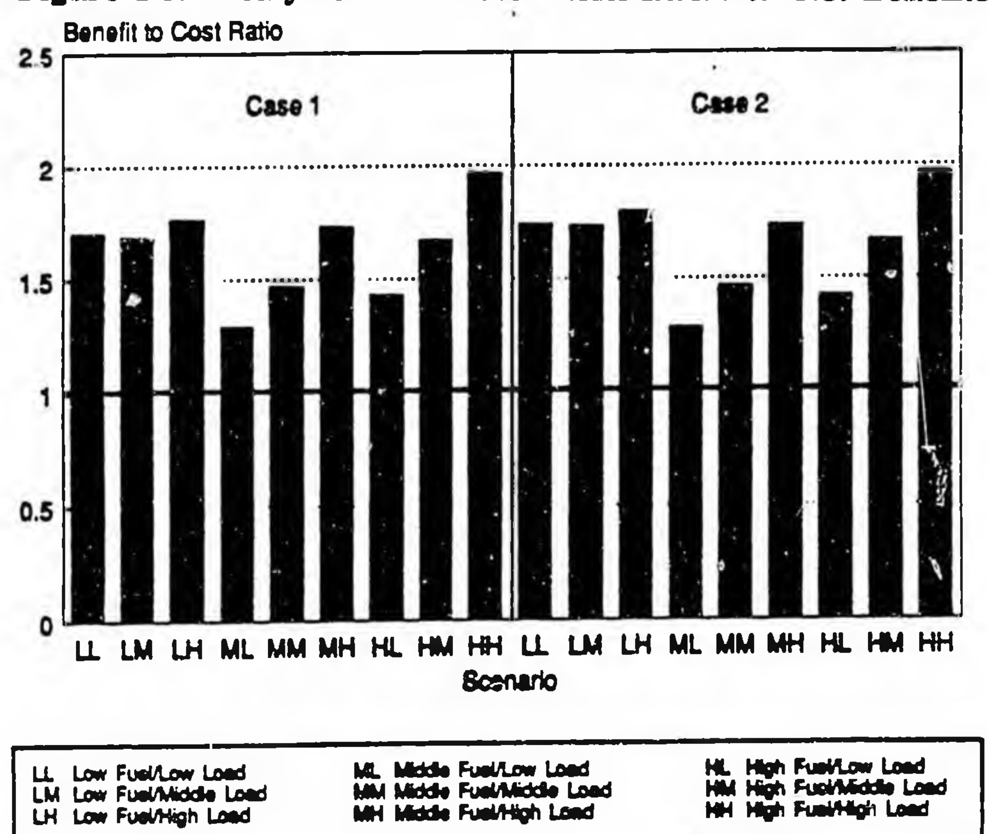


Figure 1-6. Healy-Fairbanks Northern Intertie: Benefit to Cost Ratios

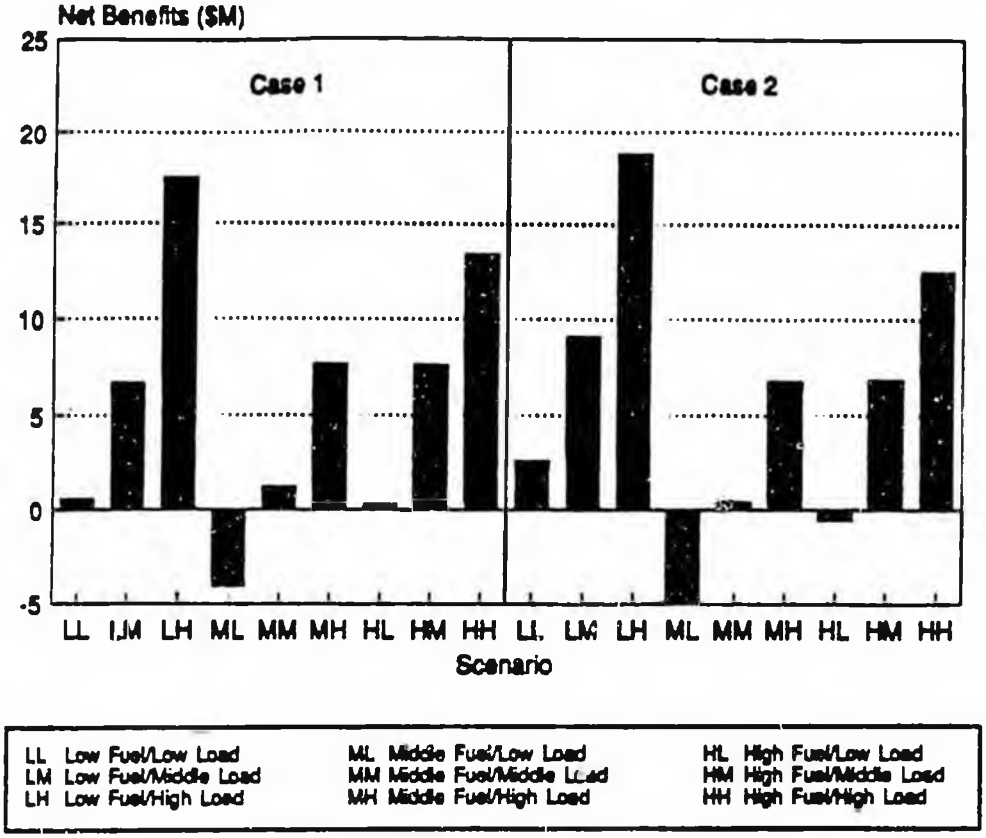


Figure 1-7. Healy-Fairbanks Northern Intertie: Net Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

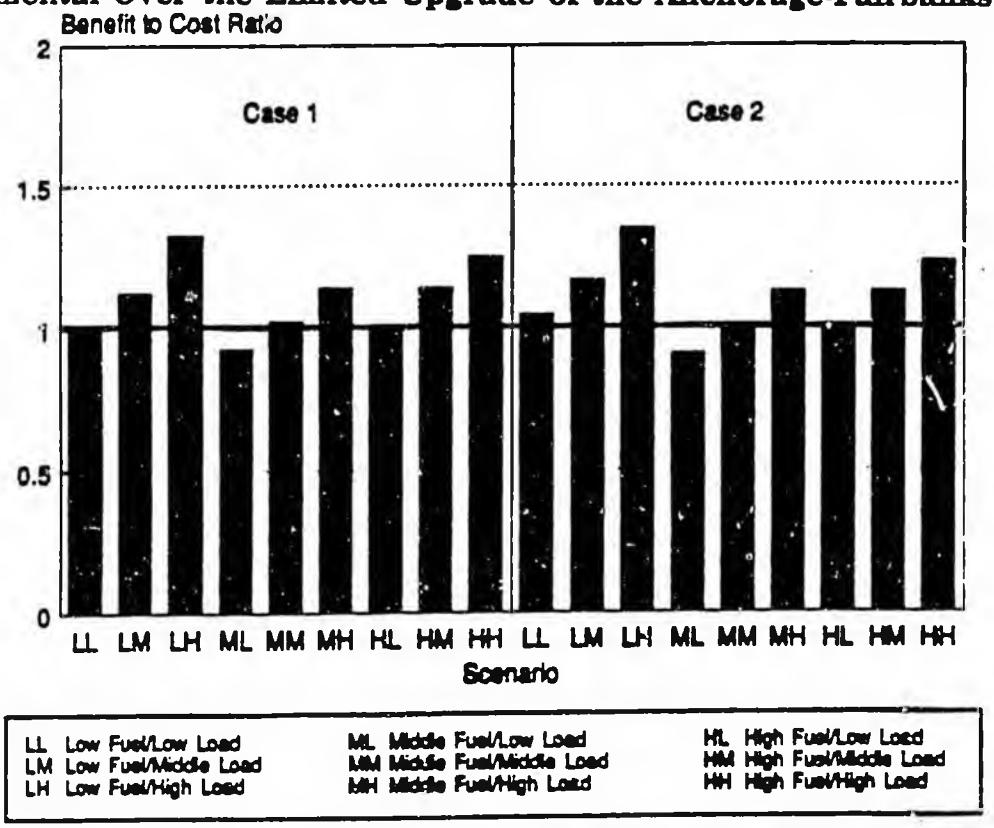


Figure 1-8. Healy-Fairbanks Northern Intertie: Benefit to Cost Ratios (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

1.5.1 New Kenai-Anchorage Intertie

This alternative consists of a new 138 KV transmission line between Anchorage and the Kenai Peninsula with a transfer capacity of 150 MW. The capital cost of the proposed Kenai-Anchorage intertie varies between $64.3 million (without replacement of the submarine cable) and $73.8 million (with replacement of the submarine cable). Operations and maintenance cost is estimated at $0.5 million per year. The present value of total costs is estimated at $74.1 million (without replacement of the submarine cable) and at $86.2 million (with the replacement of the submarine cable).

The expected value of benefits is estimated between $114.0 million and $131.3 million. This consists of the following benefits:

1. *Reliability*: The value of improved reliability due to the new intertie is estimated between $32.3 million and $49.6 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between the Kenai Peninsula and Anchorage are estimated at $43.4 million adjusted for increased transmission losses and reduced gas royalty and severance taxes.[4]

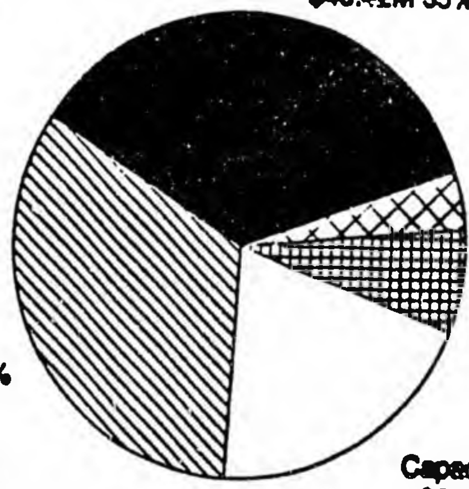
3. *Increased Capacity Sharing*: The improved transmission link would allow Anchorage to rely on a greater portion of the Kenai Peninsula generation capacity surplus for meeting the Anchorage capacity requirement. This value is estimated at $24.4 million.

4. *Increased Spinning Reserve Sharing*: Improved access to Kenai Peninsula spinning reserves is estimated to produce a value of $8.9 million.

5. *Reduced Maintenance Costs*. A second line between Kenai and Anchorage would reduce the maintenance costs of the existing line by $5 million.

Figure 1-9 shows the relative contribution of each benefit category to the total expected benefits.

4. Based on increased economy energy transfers of $51.0 million, increased transfer losses of $3.1 million and reduced gas royalty and severance taxes of $4.5 million.



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 1-9. New Kenai-Anchorage Intertie: Breakdown of Expected Benefits

1.5.2 Limited Upgrade of Anchorage-Fairbanks Intertie to 100 MW

This alternative consists of electrical equipment to provide a limited increase of 30 MW input in the transfer capacity of the existing line. The estimated capital cost of this limited upgrade is $9.4 million (again, expressed in 1990 dollars). Operations and maintenance cost is estimated at $0.05 million per year. The present value of total costs is $10.3 million.

The expected value of benefits is estimated at $45.9 million in the following categories:

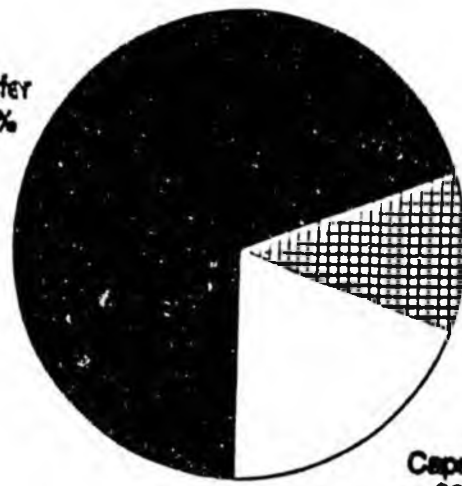
1. *Reliability*: The value of improved reliability is estimated at $5.0 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks, after adjusting for increased transmission losses and increased gas royalty and severance taxes are estimated at $31.8 million.[5]

3. *Increased Capacity Sharing Benefits*: The upgrade would allow Anchorage to rely on a greater portion of the Fairbanks generation capacity surplus for meeting the Anchorage capacity requirement. This value is estimated at $9.0 million.

Figure 1-10 shows the relative contribution of each benefit category to the total expected benefits.

5. Based on increased economy energy transfers of $42.7 million, increased transfer losses of $15.4 million and increased gas royalty and severance taxes of $4.5 million.



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 1-10. Anchorage-Fairbanks Upgrade to 100 MW: Breakdown of Expected Benefits

1.5.3 New Healy-Fairbanks Intertie

This alternative consists of the limited upgrade of the Anchorage-Fairbanks line and a new transmission line between Healy and Fairbanks. Transfer capacity between Anchorage and Fairbanks would be increased to 120-140 MW and transfer losses would be reduced. The capital cost of this proposal is $58.7 million. The additional operations and maintenance cost is estimated at $0.3 million per year. The present value of total costs is estimated at $64.6 million.

The expected value of benefits is estimated at $105.8 million in the following categories:

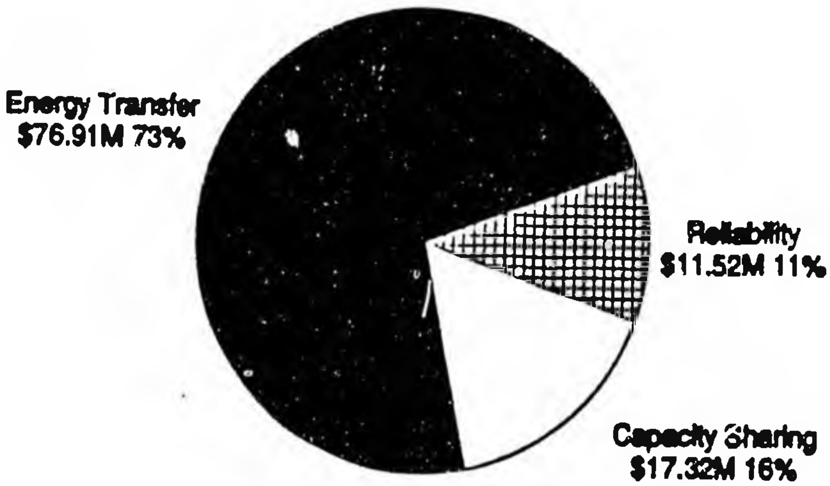
1. *Reliability*: The value of improved reliability is estimated at $11.5 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks, after adjusting for increased transmission losses and increased gas royalty and severance taxes, are estimated at $76.9 million.[6]

3. *Increased Capacity Sharing*: The upgrade would allow Anchorage to rely on a greater portion of the Fairbanks generation capacity surplus for meeting the Anchorage capacity requirement. This value is estimated at $17.3 million.

Figure 1-11 shows the relative contribution of each benefit category to the total expected benefits.

6. Based on increased economy energy transfers of $76.2 million, increased transfer losses of $7.0 million and increased gas royalty and severance taxes of $7.7 million.



Energy transfer includes transfer loss and gas royalty.
Average of all scenarios.

Figure 1-11. Healy-Fairbanks Northern Intertie: Breakdown of Expected Benefits

Section 2

DESCRIPTION AND COSTS OF PROPOSED INTERTIES

2.1 DESCRIPTION AND CAPITAL COST OF INTERTIES

This section presents a description of each of the three proposals considered in this study, and summarizes the estimated capital costs for the proposals. Power Engineers Incorporated prepared the design and cost estimates for the Kenai-Anchorage intertie. Harza Engineering Company prepared the design and cost estimates for the Anchorage-Fairbanks intertie proposals. All costs presented in this section are in 1990 dollars.

2.1.1 New Intertie Between Anchorage and the Kenai Peninsula (KA138 Intertie)

The KA138 line is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. The line is comprised of three segment types: steel and wood pole overhead lines, underground cables, and a submarine cable through Turnagain Arm. An addition to the Huffman Substation and an addition to the International Substation have been considered as design options for the substation in Anchorage.

The capital cost of the KA138 proposal, with the Huffman Substation option and a 15 percent contingency, is estimated at $64.3 million[1] in 1990 dollars. The capital cost of the KA138 proposal, with the International Substation option and a 15 percent contingency, is estimated at $65.6 million[2] in 1990 dollars.

2.1.2 Limited Upgrade of the Anchorage-Fairbanks Intertie (AF100 Upgrade)

The AF100 upgrade is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the Reconnaissance Study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW.

1. Report prepared by Power Engineers Incorporated for Chugach Electric Association, April, 1989.

2. Ibid.

The capital cost of the AF100 upgrade, with a 15 percent contingency, is estimated at $9.4 million[3] in 1990 dollars.

2.1.3 New Intertie Between Healy and Fairbanks (AF138 Intertie)

The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The proposed 138 KV line between Healy and Ft. Wainwright is a steel-structure line that will significantly reduce the losses on the line between Healy and Fairbanks, and will increase the transfer between Anchorage and Fairbanks.

The capital cost of the 138 KV line and terminal substations, with a 15 percent contingency, is estimated at $49.3 million[4] in 1990 dollars. Including the capital cost of the limited upgrade ($9.4 million in 1990 dollars), the total capital cost of the proposal is, therefore, $58.7 million.

2.2 VARIABLE COSTS OF THE PROPOSED INTERTIES

The variable costs of an intertie are the annual operating and maintenance costs that are associated with the operation of the line. These costs are typically expressed as a percent of the capital cost of the line. In the Reconnaissance Study, the variable cost of each line is estimated as 1.5 percent of capital cost.[5] The Railbelt utilities have cited historical data as evidence that the variable costs for the existing Railbelt interties are less than 1.5 percent of capital cost. The lack of existing evidence supporting the variable cost of transmission lines prompted further investigation of the estimated variable costs of the proposed lines.

2.2.1 New Evidence of the Variable Cost of the AF138 Intertie

The annual operating and maintenance expenses for the existing Anchorage-Fairbanks intertie during the past three years averaged 1.0 percent of the capital cost of the line.[6] The estimated 1989 total expenses for the Anchorage-Fairbanks intertie are $1.4 million on a capital investment of $125 million. The proposed AF138 line

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3. "Railbelt Intertie Reconnaissance Study, Benefits/Cost Analysis," prepared by Decision Focus Incorporated, for the Alaska Power Authority, June, 1989.

4. Report prepared by Harza Engineering Company for Golden Valley Electric Association, April 5, 1989.

5. Letter from Steven Haagenson, Golden Valley Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated August 25, 1989.

6. Letter from Myles Yerkes, Matanuska Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated August 25, 1989.

would be a second line between Healy and Fairbanks; and some of the operating and maintenance functions would not require duplication.

For example, the AF138 line would not increase wheeling and dispatch costs. The administrative and general costs for a second intertie should be proportionally less than the current expenses to reflect an adjustment for wheeling and dispatch costs. The 1989 wheeling and dispatch costs are estimated at $0.6 million; and the administrative and general costs are $0.3 million. The adjusted administrative and general costs are $0.1 million ([(1.4 - 0.6 - 0.3)/(1.4 - 0.3)] * 0.3). With the adjustments for expenses that would not be duplicated, the estimated 1989 expenses would be $0.6 million (1.4 - 0.6 - .2), or 0.5 percent of the capital cost of the intertie.

Peter Donalek at Harza Engineering Company has confirmed the fact that 0.5 percent of capital cost is a reasonable estimate of the operating cost of a second intertie between Healy and Fairbanks.[7] He cited two pieces of evidence. First, the accepted industry standards for estimating the variable operating cost of a line are in the range of 0.5 to 1.5 percent. A steel-structure line in Alaska should require very low maintenance and should, therefore, be at the low end of the range. Second, the best estimate of the operating costs of a new line is the historical operating costs of similar lines in the region. Variable costs are extremely location-specific and industry averages are not particularly good estimates. This evidence was also confirmed by Barry Flynn of Flynn & Associates.[8]

We assume that the variable costs of the AF100 and AF138 lines are 0.5 percent of capital cost of the interties. Given these assumptions, the annual variable cost associated with the AF100 upgrade is $0.05 million per year in 1990 dollars. The annual variable cost associated with the AF138 intertie is estimated at $0.3 million per year in 1990 dollars.

2.2.2 New Evidence of the Variable Cost of the KA138 Line

The KA138 line is likely to have higher operating and maintenance costs than the proposed AF138 line. According to John McGrew at Power Engineers, a submarine cable has a considerably higher risk of damage from hazard than an overhead line. In addition to the risk of damage from boats in Alaska, there can be problems with ice gauging that can prematurely cut the life of a line short.[9] This information was

7. Phone conversation between Peter Donalek, Harza Engineering Company, and Carol Redfield, Decision Focus Incorporated, October 27, 1989.

8. Letter from Barry Flynn, Flynn & Associates, to Salim Jabbour, Decision Focus Incorporated, dated November 1, 1989.

9. Phone conversation between John McGrew, Power Engineers, and Carol Redfield, Decision Focus Incorporated, October 27, 1989.

confirmed for us by Ralph Samm, Manager of the Underground Transmission Program at EPRI.[10]

Problems from ice gauging and changing bottom contours have plagued the existing submarine cables in the Knik Arm of Cook Inlet. These lines are due for a complete replacement in 1990, approximately 15 years after they were originally built.

The submarine cables proposed for the KA138 line should not be subject to the same level of hazard as the current lines in Knik Arm. The KA138 submarine cable is designed to go through Turnagain Arm. The exposure to boat and ice hazards in Turnagain Arm should be less than in Knik Arm.

Given these facts, there is a probability that the new submarine cable will need to be replaced in the future. Assuming a complete replacement of the cable after twenty years, and a capital cost (with a 15-percent contingency) of $22.9 million in 1990 dollars, the present value of replacing the line in 20 years is $9.5 million.

We assume a variable operating and maintenance cost of 1.5 percent of the cost of capital for the submarine cable for an annual variable cost of $0.3 million. The remainder of the KA138 intertie is comprised of wood-pole and underground lines that should require minimal maintenance.[11] We assume that the variable cost of the intertie, excluding the submarine cable, will be 0.5 percent of the capital cost of the line.[12] Under these assumptions the annual variable cost of the line, excluding the submarine case, would be $0.2 million per year. The total variable operating and maintenance cost of the line is, therefore, $0.5 million per year in 1990 dollars.

2.3 ECONOMIC LIFE OF THE INTERTIES

The expected economic life of an intertie is used to determine the net present value of the annual variable costs of the line. The Reconnaissance Study assumes that the economic life of each of the proposed lines is 35 years. The Railbelt utilities indicated that the life of a line may be as long as 50 years. Further investigation indicated the following information.

10. Phone conversation between Ralph Samm, Manager of the Underground Transmission Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated, October, 1989.

11. Phone conversation between Harry Ng, Project Manager, Distribution Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated, October, 1989.

12. The capital cost of the line, excluding the submarine cable, is $41.4 million.

2.3.1 New Evidence of the Economic Life of the AF100 and AF138 Interties

The AF138 line is a steel-structure line. B.C. Hydro amortizes steel-pole lines over a 50-year horizon. B.C. Hydro currently has steel-pole lines in operation that were built in 1932 and, therefore, considers 50 years a "safe" assumption.[13] Bonneville Power currently amortizes lines over 44 years. However, Bonneville Power assumes that new technology should increase the expected life of new lines to 50 years.[14] In the design of the AF line, Commonwealth Associates assumes a 50-year life for the steel-pole lines.[15] According to Barry Flynn,[16] Pacific Gas and Electric's lattice-steel lines that were built in 1904 and 1906 continue to operate today in a reliable manner, as do wood-pole lines built in 1910 and 1922.

Harry Ng, a Transmission Engineer at EPRI, confirmed Bonneville Power's observation that most of the steel-pole lines that have been constructed to date are still in operation; and no one knows for sure how long they will last. He noted that most utilities assume a 40- to 50-year life for all lines.[17]

Based on this evidence we assume a 50-year life for the AF138 line.

2.3.2 New Evidence of the Economic Life of the KA138 Line

The KA138 line is primarily composed of wood-pole lines and a submarine cable. There is a broad range of estimates for the life of a wood-pole line. According to Paul Lyons of EPRI, a wood-pole line may last as little as 10 years in a humid climate, such as Florida, due to deterioration from fungus and pests.[18] In the Southwest, a wood-pole line may last well beyond 50 years. In the Alaska climate, wood-pole lines should have minimal problems with fungus and pests; and lines should last anywhere from 35 to 50 years.

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13. Phone conversation between Bob Loose, BC Hydro, and Carol Redfield, Decision Focus Incorporated, October, 1989.

14. See note 6.

15. "Anchorage-Fairbanks Transmission Intertie Structure Study for Alaska Power Authority," prepared by Commonwealth Associates, Inc., Jackson, Michigan, August, 1981

16. See note 8.

17. See note 11.

18. Phone conversation between Paul Lyons, Project Manager in the Overhead Transmission Lines Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated. October, 1989.

Commonwealth Associates assumes a 35-year life for the wood-pole lines in the design proposal for the AF line.[19] Bonneville Power and B.C. Hydro[20] amortize wood-pole lines over 39- and 50-year horizons, respectively. Harza Engineering Company estimates that the lines should have a 40-year life.[21] We assume that the life of a wood-pole line in Alaska should be 40 years.

Without the occurrence of an unanticipated hazard, a submarine cable should last as long as any other line. However, any hazard has the risk of cutting short the life of the line. Ralph Samm, at EPRI, estimates the average life of a submarine cable to be 40 years—the "industry average for any type of line".[22] We consider the risk of a hazard that might cut short the life of the cable by evaluating the possibility of a complete replacement after 20 years of service (refer to Section 2.2.2).

Given this evidence, we assume a 40-year life for the entire KA138 line.

2.4 NET PRESENT VALUE OF THE COST OF THE PROPOSED INTERTIES

Assuming a 40-year life for the entire KA138 line and a discount rate of 4.5 percent, the net present value of the variable cost of the line is $9.7 million with the Huffman Substation option. The total cost of this proposal is $74.1 million with no replacement of the submarine cable.[23] Assuming a replacement of the cable after twenty years, the total cost of the KA138 proposal, with the Huffman station, is $86.2 million in 1990 dollars.

Assuming a 50-year life for the AF100 upgrade, the net present value of the variable costs associated with the upgrade is $0.9 million. The total cost of the AF100 proposal is $10.3 million, again in 1990 dollars.

Assuming a 50-year life for the AF138 intertie, the net present value of the variable costs associated with the intertie is $5.8 million. The total cost of the AF138 proposal is $64.6 million in 1990 dollars.

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19. See note 14.

20. See note 12.

21. See note 7.

22. See note 10.

23. With the International Substation option, the net present value of the variable costs is $10.1 million and the total cost is $75.6 million, all in 1990 dollars.

Section 3

TRANSFER LOSSES OF EXISTING AND PROPOSED TRANSMISSION LINES

Transmission losses play an important role in the cost of power transfer between two distant areas. Since energy lost in transmission can be considered to have the same value as delivered power, an understanding of electrical losses is vital to evaluate the benefits of a transmission addition. Losses are considered for the limited upgrade of the Anchorage-Fairbanks line (AF100), the new intertie between Healy and Fairbanks (AF138), and the new intertie between Kenai and Anchorage (KA138).

3.1 ANCHORAGE-FAIRBANKS NEW/UPGRADED INTERTIES

Under the limited upgrade of the Anchorage-Fairbanks line (AF100), transmission losses are the same as the existing intertie; this is because the only change to the intertie is installation of stability equipment, which increases the transfer limit but does not impact losses. Therefore, additional loss calculations for the AF100 are required for the increased levels of transfer.

A major portion of the losses between Anchorage and Fairbanks for the existing and AF100 lines occur between Healy and Fairbanks. The following analysis shows that the proposed 138 KV line from Healy to Fairbanks (AF138) will significantly reduce losses by increasing transfer efficiency.

3.1.1 Calculation of Losses

Power Technologies Incorporated (PTI) provided a technical memorandum on losses and compensation requirements to the Golden Valley Electric Association in April, 1989.[1] This report detailed the technical power flow analysis necessary to assess the impact of the AF138 on transmission losses.

1. Power Technologies Incorporated, "Healy—Ft. Wainwright Line: Losses and Compensation Requirements," submitted to Steve Haagenson, Golden Valley Electric Association, April 4, 1989.

Characteristics of the existing and proposed lines were used by PTI to evaluate losses for several levels of power flow on the lines. PTI calculated transmission losses for the AF100 and the AF138 for six levels of load in the Fairbanks area.[2] Table 3-1 shows losses for the first three cases, which involve loads of 50 percent, 75 percent, and 100 percent of 115 MW at Fairbanks. Table 3-2 shows losses for the second three cases, which involve loads of 50 percent, 75 percent, and 100 percent of 124.2 MW at Fairbanks. The choice of 124.2 MW at Fairbanks in the second set of cases is important. This load level corresponds to a flow into Healy of 105.6 MW for the AF138, which matches exactly the Healy flow for the AF100 and 115.0 MW at Anchorage (refer to Footnotes 3 and 5). The result is that the impact of the addition on losses can be directly evaluated, since the power input at Healy has been held constant (105.6 MW). Therefore, a good comparison could be made between the AF100 losses in Table 3-1 and the AF138 losses in Table 3-2.

Adapting the results from the PTI report, losses have been divided among the Anchorage area, transfer between Anchorage and Healy, and transfer between Healy and Fairbanks.

Table 3-1[3]

ANCHORAGE-FAIRBANKS TRANSFER LOSSES (MW)

	Fairbanks Load (100% = 115 MW)		
	100%	75%	50%
Anchorage Area[4]			
AF138	7.1	3.5	1.3
AF100	8.5	4.0	1.4
Anchorage to Fairbanks			
AF138	10.4	5.3	2.2
AF100	21.8	10.4	4.1

2. In all cases there is no generation in the Fairbanks area.

3. Power flows into Healy for the AF138 are 95.4, 64.4, and 34.0 MW at 100, 75, and 50 percent load levels. Power flows into Healy for the AF100 are 105.6, 69.1, and 35.9 MW at 100, 75, and 50 percent load levels.

4. Losses shown are the total losses in the Anchorage minus those losses which are not due to transfers to Fairbanks (estimated at 12 MW, based on consultation with PTI). These "variable losses" increase with the power transferred from Anchorage to Fairbanks.

Table 3-2[5]

ANCHORAGE-FAIRBANKS TRANSFER LOSSES
(MW)

	Fairbanks Load (100% = 124.2 MW)		
	100%	75%	50%
Anchorage Area[6]			
AF138	8.6	4.2	1.6
AF100	10.9	4.8	1.7
Anchorage to Fairbanks			
AF138	12.6	6.4	2.5
AF100	28.2	12.5	4.9

Data from Tables 3-1 and 3-2 was incorporated into Tables 3-3 and 3-4, which show loss calculations for the AF100 intertie upgrade and AF138 new intertie for different input levels at Anchorage.

Table 3-3

AF100 NEW INTERTIE BREAKDOWN OF TRANSFER LOSSES

MW at FBX	MW at Healy			AF Losses			Anch Loss	MW at Anch	Total Losses		
	Anch	Healy	Total	HF	AH	Total			MW	%input	Incr
124.2	119.2	25.0	144.2	20.0	8.2	28.2	10.9	138.3	39.1	28.3	48.9
115.0	105.6	25.0	130.6	15.6	6.2	21.8	8.5	120.3	30.3	25.2	37.3
93.2	77.4	25.0	102.4	9.3	3.3	12.5	4.8	85.5	17.3	20.2	29.6
86.3	69.1	25.0	94.1	7.8	2.6	10.4	4.0	75.7	14.4	19.0	24.4
62.1	41.1	25.0	66.1	4.0	0.9	4.9	1.7	43.7	6.6	15.1	19.3
57.5	35.9	25.0	60.9	3.4	0.7	4.1	1.4	38.0	5.5	14.5	14.5
Col. 1	2	3	4	5	6	7	8	9	10	11	12

5. Power flows into Healy for the AF138 are 105.6, 71.8, and 38.8 MW for 100, 75, and 50 percent load levels. Power flows into Healy for the AF100 are 119.2, 77.4, and 41.1 MW for 100, 75, and 50 percent load levels.

6. See Footnote 4.

Table 3-4

AF138 INTERTIE UPGRADE
BREAKDOWN OF TRANSFER LOSSES

MW at FBX	MW at Healy			AF Losses			Anch Loss	MW at Anch	Total Losses		
	Anch	Healy	Total	HF	AH	Total			MW	%input	Incr
124.2	105.6	25.0	130.6	6.4	6.2	12.6	20.6	120.4	21.2	17.6	28.7
115.0	95.4	25.0	120.4	5.4	5.0	10.4	19.1	107.5	17.5	16.3	24.0
93.2	71.8	25.0	96.8	3.6	2.8	6.4	16.2	78.8	10.6	13.5	20.7
86.3	64.4	25.0	89.4	3.2	2.1	5.3	15.5	70.1	8.8	12.6	16.3
62.1	38.8	25.0	63.8	1.7	0.8	2.5	13.6	41.2	4.1	10.0	11.5
57.5	34.0	25.0	59.0	1.5	0.7	2.2	13.3	36.0	3.5	9.7	9.7

For each table, the power in MW at each node is identified, as well as the losses incurred between the nodes. For example, consider the first row of Table 3-3, which takes data from the 100% load column of Table 3-2.

In Table 3-3 Column 1 (124.2 MW), the load at Fairbanks; Column 2 (119.2 MW), the flow into Healy from Anchorage; and Column 7 (28.2 MW), the total losses, are all taken from Table 3-2. The local generation in Healy (25.0 MW), shown in Column 3, is added to the Anchorage portion (119.2 MW) to arrive at the total power at Healy (144.2 MW) in Column 4. Column 5 is the loss from Healy to Fairbanks (20.0 MW), and is calculated as the difference between the total power at Fairbanks (Column 1) and the total power at Healy (Column 4). Column 6 is the loss from Anchorage to Healy (8.2 MW), and is calculated as the difference between total losses (Column 7) and the losses from Healy to Fairbanks (Column 5).

Column 8, the losses in Anchorage (10.9 MW), is taken from Table 3-2. The power at Anchorage (138.3 MW) is calculated by adding the losses from Anchorage to Healy (8.2 MW) to the Anchorage portion of the power at Healy (119.2 MW). Columns 7 and 8 are added to find the total losses from Anchorage to Fairbanks (39.1 MW) in Column 10. Column 11 calculates total losses as a percent of the input power at Anchorage (39.1/138.3 = 28.3%). Incremental loss percentage is calculated in Column 12 ([39.1-30.3]/[138.3-120.3] = 48.9%)

3.1.2 Generalization of Losses

With Tables 3-3 and 3-4, loss calculations can be made at other transfer levels by interpolation. Whenever intermediate loss computations are necessary, loss is assumed to follow a squared relation to the power transferred. This is a basic result of power transfer, where power loss is equal to the square of the current times the impedance, and the current is in direct proportion to the power transferred. For example, if transmission loss (L_R) between two nodes is known at some reference transfer level (T_R), then the transmission loss L at transfer level T can be estimated as:

$$L = L_R (T/T_R)^2$$

All such calculations are referenced to the closest data input given in PTI's analysis. Transmission losses of Healy generation contributes to total losses, but the generated power is not included in the base amount of generation to which the percent loss is referred. This allows Over/Under to model Healy as part of the Fairbanks area, recognizing losses from Healy to Fairbanks, but only as a percentage of power input at Anchorage.

Historically, 62 MW has been the limit of power delivered to Fairbanks on the Anchorage-Fairbanks intertie. It was reported and used in the Reconnaissance Study that the power input to achieve 62 MW at Fairbanks is 70 MW at Anchorage.[7] The 70 MW input, however, only considered losses north of Anchorage; if losses in the Anchorage area were included (as they are for this analysis), an input greater than 70 MW would be needed to deliver 62 MW at Fairbanks. The second row of Table 3-5 shows that for an input of 70 MW at Anchorage, losses would equal 12.6 MW, making the delivered power to Fairbanks equal to 57.4 MW.

Table 3-5

TRANSMISSION LOSSES FOR THE EXISTING ANCHORAGE-FAIRBANKS INTERTIE

Anchorage Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	5.8	14.5	14.5
70.0	12.6	18.0	22.8
77.0	14.8	19.3	32.1

The transfer limit of the AF100 would be either 84 MW (Case 1) or 87 MW (Case 2), delivered to Fairbanks. In order to deliver 84 MW to Fairbanks, roughly 110 MW is needed as input at Anchorage. Several increments of transfer levels up to

7. Railbelt Intertie Reconnaissance Study, Section 2, page 2-3.

110 MW have been chosen to provide intermediate detail for use of the loss calculations in the Over/Under simulations. Table 3-6 outlines AF100 losses, relating the level of power generated at Anchorage and total transmission losses from Anchorage to Fairbanks. Losses are shown in terms of MW input at Anchorage, as percent of input power, and as percentage incremental losses.

Table 3-6

TRANSMISSION LOSSES FOR THE AF100 INTERTIE UPGRADE

Anchorage Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	5.8	14.5	14.5
70.0	12.6	18.0	22.8
100.0	22.3	22.3	32.1
110.0	26.9	24.5	46.8

Table 3-7 shows losses for the AF138 new intertie, again breaking transfer levels into several increments to provide representative detail for the Over/Under simulations. The highest level of transfer in Table 3-7 corresponds to an input of 140 MW at Anchorage, resulting in a delivery of 112 MW in Fairbanks, which is the limit expected for the AF138 in Case 2.

Table 3-7

TRANSMISSION LOSSES FOR THE AF138 NEW INTERTIE

Anchorage Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	3.8	9.5	9.5
70.0	8.8	12.6	16.7
100.0	15.6	15.6	22.6
120.0	21.3	17.8	28.6
140.0	28.1	20.1	34.1

3.2 KENAI-ANCHORAGE NEW INTERTIE (KA138)

Transfer between the Kenai-Anchorage has been taken from the Reconnaissance Study.[8] Table 3-8 shows the losses for several levels of transfer on the existing 115 KV intertie between Kenai and Anchorage. Case 1 assumes a transfer limit of 70 MW input at Kenai and 61 MW output at Anchorage. Case 2 assumes a transfer limit of 90 MW input at Kenai and 75 MW output at Anchorage.

Table 3-9 shows the losses for several levels of transfer for the case of a second intertie (138 KV) between Kenai and Anchorage.

Table 3-8

TRANSMISSION LOSSES FOR THE EXISTING KENAI-ANCHORAGE INTERTIE

Kenai Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	3.6	8.9	8.9
60.0	6.9	11.5	16.6
70.0	8.8	12.6	19.2
90.0	14.5	15.6	28.7

Table 3-9

TRANSMISSION LOSSES FOR THE NEW KENAI-ANCHORAGE INTERTIE (KA138)

Kenai Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
60.0	2.5	4.2	4.2
90.0	5.6	6.2	10.2
100.0	6.9	6.9	13.2
120.0	9.9	8.3	15.2
150.0	15.4	10.3	18.6

8. Losses at transfer levels not reported in the Reconnaissance Study were calculated using the approach outlined in Section 3.1.2.

Section 4

RELIABILITY BENEFITS OF PROPOSED 138 KV INTERTIES

This section analyzes the effects that the proposed interties would have on service reliability. Reliability is important because the value of electric power exceeds the cost of producing the power. The cost to a utility of an outage may be small, while the cost of that same outage to an industrial or commercial customer may be very large. The proposed upgraded or new interties will improve service reliability by reducing both the frequency and duration of customer outages.

The assessment of the value of improved system reliability requires an estimate of the outages that an intertie will avoid and the cost to customers of the outages that are avoided. We estimate the impact of the interties on customer outages by analyzing the historical outages in the Railbelt area and the changes that the interties should bring about.

For the costs of customer outages, we have relied on research compiled by the Electric Power Research Institute (EPRI) on the value of service reliability [1]. Since the completion of the Reconnaissance Study, a new EPRI study on service reliability was released. The new study presents substantial evidence that the costs of customer outages are significantly higher than previously estimated. The new evidence is presented in the analysis that follows.

This section is divided into four parts. First, we review the historical levels of customer unserved energy. Second, we estimate the impact that the proposed interties will have on customer unserved energy. Third, we review the new evidence of the costs of customer outages presented in the 1989 EPRI report. Fourth, we apply the costs of outages to the estimate of the impact that the interties will have on customer outages to assign a dollar value to the reliability benefits of the interties.

4.1 IMPACT OF PROPOSED INTERTIES ON CUSTOMER UNSERVED ENERGY

In the event of an outage, customer unserved energy is the electrical energy that would have been demanded by customers if the outage had not occurred. The impact of the interties on customer unserved energy is the change in customer outages that the interties are expected to bring about.

4.1.1 Historical Customer Unserved Energy

For the Reconnaissance Study, data on historical customer outages in the Railbelt region was collected from each of the Railbelt utilities.[1] The customer unserved energy in the Railbelt averaged 955 MWh/year for 1986/1987. Residential customers experienced 44 percent of the unserved energy. A majority of the outages were in Anchorage with an average 655 MWh of unserved energy, or 69 percent of all Railbelt outages. Kenai averaged 192 MWh of outages and Fairbanks averaged 104 MWh of unserved energy.

4.1.2 Impact of the KA138 Intertie on Customer Unserved Energy

The KA138 line is proposed for the same route as the KA line analyzed in the Reconnaissance Study. Similar to the KA line, it would be a second line between Kenai and Anchorage, and, presumably, would be constructed to the same reliability standards as the KA line. Because of this, we assume that it should have the same impact on customer unserved energy as the KA line. We summarize below the expected impact of a new KA intertie on customer unserved energy based on the analysis presented in the Reconnaissance Study.[2]

The KA line is expected to save between 20 and 80 percent of Kenai customer unserved energy when Kenai is exporting power, and 50 percent of unserved energy when Kenai is importing power. The exception to this are Seward outages which will not be avoided by the new interties. Kenai is expected to be an exporter of power 40 percent of the time and an importer 60 percent of the time. We analyze a low case of 46 percent of outages avoided (40 percent of outages avoided 40 percent of the time, and 50 percent of the outages avoided 60 percent of the time) and a high case of 62 percent of outages avoided (80 percent of outages avoided 40 percent of the time, and 50 percent of outages avoided 60 percent of the time).

The KA line would avoid outages in Anchorage when Anchorage is importing power from Kenai (40 percent of the time). It should, therefore, avoid 1.2 outages per year (40 percent of an average 3 outages per year). We analyze a low case of one avoided outage per year of one hour in duration, and a high case of two avoided outages per year of one hour duration. Each outage is limited to 30 MW due to the availability of spinning reserves in Anchorage.

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1. Refer to "Railbelt Intertie Reconnaissance Study," Appendix A, Prepared by Decision Focus Incorporated for Alaska Energy Authority, June 1989.

2. Refer to "Railbelt Intertie Reconnaissance Study," Section 4, Prepared by Decision Focus Incorporated for Alaska Energy Authority, June 1989.

4.1.3 Impact of the AF100 Intertie on Customer Unserved Energy

As determined in the Reconnaissance Study, the AF100 upgrade should save 10 percent of MEA outages due to reduced outage duration in the area.

4.1.4 Impact of the AF138 Intertie on Customer Unserved Energy

The AF138 line is comprised of the AF100 upgrade coupled with a new 138 KV line between Healy and Fairbanks. In addition to avoiding 10 percent of MEA outages due to the AF100 upgrade, the AF138 proposal will achieve reliability benefits due to the construction of a second intertie between Healy and Fairbanks.

The AF138 line provides an alternate route between Healy and Fairbanks. Because Fairbanks is typically an importer of power from Anchorage, the second line would avoid some outages in the Fairbanks area. The Northeast intertie analyzed in the Reconnaissance Study was estimated to save 40 percent of Fairbanks outages by providing an alternate route between the two areas. Since the distance from Healy to Fairbanks is approximately one-third of the distance from Anchorage to Fairbanks, we estimate that the AF138 intertie would avoid 12 percent of Fairbanks outages (one-third of the 40 percent of the Fairbanks outages that the Northeast intertie would avoid).

Table 4-1 summarizes the expected impacts of the proposed 138 KV interties on customer unserved energy.

Table 4-1

SUMMARY OF UNSERVED ENERGY FOR THE 138 KV INTERTIES

Area	KA138 Low Case	KA138 High Case	AF100 Intertie	AF138 Intertie
Kenai	46% of Kenai unserved energy saved	62% of Kenai unserved energy saved	0	0
Anchorage	30 MWh of unserved energy saved	60 MWh of unserved energy saved	10% MEA unserved energy saved	10% MEA unserved energy saved
Fairbanks	0	0	0	12% Fairbanks unserved energy saved

4.2 COSTS OF CUSTOMER OUTAGES

The cost of a customer outage is the value to a customer of unserved energy. There are several ways to estimate the cost of an outage resulting in a wide range of cost estimates. The most widely accepted estimation methods in recent years are survey techniques that ask customers to assess the value of the losses suffered during an outage.[3]

The Reconnaissance Study relied on outage cost data from a 1986 EPRI report on service reliability. From that study, the results of the Ontario Hydro surveys of outage costs for industrial and commercial customers, as presented by Scott, were selected as the most applicable to the Railbelt [2]. Since the completion of the Reconnaissance Study, EPRI has released a new study of service reliability that presents updated evidence on the value of service reliability [3].

The new data provided in the 1989 study impacts the analysis of the benefits of the proposed interties in two ways:

1. The study indicates that the cost of residential outages may be considerably higher than previously estimated.

2. The study reveals new information about the Ontario Hydro survey results that was not evident from the Scott summary in the 1986 Study.

The new evidence on the cost of outages results in significantly higher estimates of outage costs for both residential and commercial/industrial customers. The reliability benefits in this analysis are, therefore, significantly higher than the benefits estimated in the Reconnaissance Study.

4.2.1 New Evidence on the Costs of Residential Outages

The Reconnaissance Study uses estimates of residential outage costs from a study completed by Sangvhi in 1983 [4]. Sangvhi estimates that the unit cost of a residential outage is in the range of $0.07/KWh to $2.07/KWh (in 1987 dollars). More recent surveys have yielded considerably higher estimates of the costs of residential customer outages.

3. Refer to "Customer Demand for Service Reliability," Section 2, Prepared for Electric Power Research Institute by Laurits R. Christensen Associates, Inc., Madison, Wisconsin, May 1989.

The preferred methods for customer surveys in recent studies are the *Direct Cost* and the *Willingness-to-Pay* survey approaches.[4] The *Direct Cost* approach asks customers to assess the total loss that would occur in the event of an outage. The *Willingness-to-Pay* approach asks customers to assess what they would be willing to pay to avoid an outage. The range of outage costs resulting from these survey techniques is broad. The variation is partly explained by the wide variety of the survey techniques. It is also due to differences in the customers experience with outages. Customers who have not experienced many outages may give very different responses than customers who experience frequent outages.

The range of survey results from the 1989 EPRI study is presented in Table 4-2. The costs range from $0.21/KWh to $9.91/KWh. For this analysis we assume a unit cost of $5.00/KWh for residential outages. This value is approximately the midpoint of the range of survey results.

Table 4-2

RESIDENTIAL OUTAGE COSTS
(1990 $)

Source	Condition	Method	$/KW
Sangvhi (1983)	---	Proxi	2.07
Ontario Hydro (1980)	---	WTP	0.21
Billington, et al. (1982)	---	Direct	1.76
Doane, et al. (1989)	Annual average*	Direct	10.17
Doane, et al. (1989)	Annual average*	Direct	9.39
Goett, et al. (1989)	Winter	WTP	2.18
Meta Systems, et al (1986)	Annual average*	WTP	3.45

WTP = Willingness to Pay

Source: "Customer Demand for Service Reliability," EPRI, EA-4494, May 1986.

*For surveys that estimated separate winter and summer estimates of outage costs, we calculated an annual average outage cost assuming 50 percent summer and 50 percent winter.

4. Refer to "Customer Demand for Service Reliability," Section 2, Electric Power Research Institute, May 1989.

4.2.2 New Evidence on the Costs of Commercial/Industrial Outages

The unit cost of a commercial or industrial outage can vary greatly with the duration of the outage. The cost per kilowatt hour of a five-minute outage is usually higher than the cost per kilowatt hour of a one-hour outage. However, the total cost of a one-hour outage exceeds the total cost of a five-minute outage.

The Ontario Hydro surveys asked customers to assess the total cost of an outage for a number of different outage durations. At the time of the survey, no attempt was made to assess the customer usage during an outage. The results of the Ontario Hydro surveys have been converted to an assessment of the cost per kilowatt hour of an outage by making an assumption about the usage at the time of an outage. The assumption that is made about usage can result in widely varying assumptions about the cost per kilowatt hour of an outage.

In his 1983 article [5], Len Scott uses the results of the Ontario Hydro surveys to calculate an estimate of the dollar per kilowatt hour cost of an outage. To convert the survey results, given in dollars per outage to dollars per kilowatt hour, Scott's results assume that the usage in Ontario was equal to 75 percent of the annual peak demand at the time of an outage. Scott's results are presented for different outage durations and different customer types in Table 4-3.

Table 4-3

CUSTOMER OUTAGE COSTS ASSUMING USAGE IS 75 PERCENT OF PEAK DEMAND

	UNIT OUTAGE COST ($/KWH, 1980 $)					COMMERCIAL/IND	
Outage	Lg Ind	Sm Ind	Building	Retail	Inst	$1980/MWh	$1980/MW
1 min	61.80	69.00	195.00	23.40	1.80	58781	980
5 min	15.97	18.68	47.77	8.57	0.92	15923	1327
10 min	10.24	12.38	29.35	6.71	0.80	10563	1761
15 min	8.33	10.28	23.21	6.09	0.77	8772	2193
20 min	7.38	9.24	20.16	5.79	0.75	7887	2629
1 hour	3.97	6.31	14.33	7.32	1.01	6987	6987
2 hours	3.12	5.34	13.02	8.33	1.06	7056	14112
4 hours	2.26	4.37	11.71	9.33	1.11	7120	28480
8 hours	1.66	4.03	10.14	12.28	2.2	8273	66184
10 hours	1.34	3.1	8.57	15.23	2.2	9198	91980

In the 1989 EPRI reliability report, Christensen Associates presented the results of the same Ontario Hydro surveys shown in the Scott report. Rather than assuming that the customer usage at the time of an outage was equal to 75 percent of the annual peak demand, Christensen Associates presented a range of possible costs per kilowatt hour for an outage based on a range of assumptions about the customer usage at the time of an outage. At one end of the range, they assumed that customer usage is 75 percent of annual peak demand. At the other end of the range, they assume that customer usage is equal to the average annual demand for each customer type surveyed.[5]

The results for the unit cost of an outage assuming annual average demand, as shown in the 1989 EPRI report, are presented in Table 4-4. Clearly, neither table is right or wrong, they are simply different interpretations of the same surveys. Using Table 4-3 and assuming that customer usage at the time of an outage is 75 percent of annual peak demand would lead to the same outage cost (in dollars per outage) calculated by using Table 4-4 and assuming that customer usage at the time of an outage is equal to the average annual demand.

Table 4-4

CUSTOMER OUTAGE COSTS ASSUMING USAGE IS ANNUAL AVERAGE DEMAND

	UNIT OUTAGE COSTS ($/KWH, 1980 $)					COMMERCIAL/IND	
Outage	Lg Ind	Sm Ind	Building	Retail	Inst	$1980/MWh	$1980/MW
1 min	224.00	162.11	480.99	38.30	3.18	143119	2385
5 min	57.88	43.89	117.83	14.03	1.62	37795	3148
10 min	37.12	29.09	72.40	10.98	1.41	24612	4100
15 min	30.19	24.15	57.25	9.97	1.36	20221	5055
20 min	26.75	21.71	49.73	9.48	1.32	18044	6009
1 hour	14.39	14.82	35.35	11.98	1.78	14830	14829
2 hours	11.31	12.55	32.12	13.64	1.87	14525	29050
4 hours	8.19	10.27	28.88	15.27	1.96	14209	56836
8 hours	6.02	9.47	25.01	20.10	3.89	15734	125867
10 hours	4.86	7.28	21.14	24.93	3.89	16895	168951

In our analysis, the total cost of a customer outage in the Railbelt area is calculated by multiplying the annual average customer usage by the estimated cost per kilowatt hour of an outage and by the duration of an outage. To be consistent with this calculation of total outage costs we, therefore, have used the unit outage costs calculated assuming customer usage equal to annual average demand as presented in Table 4-4.

The Reconnaissance Study was completed before the 1989 reliability report was made available, which clarified the different assumptions about customer usage that have been used to interpret the Ontario Hydro survey results. The reliability benefits in that study were calculated with the outage costs as interpreted by Scott and presented in Table 4-4. As a result, the reliability benefits in that study were

5. Phone conversation with David Glyes at Laurits Christensen Associates, October, 1989.

calculated with a significantly lower estimate of the cost of an outage than implied by the Ontario Hydro surveys. This analysis makes the appropriate correction. Hence, the reliability benefits in the Reconnaissance Study are less than the benefits from this analysis.

The total cost of a customer outage is calculated as the customer unserved energy times the unit cost of an outage. Table 4-5 shows for each customer type and outage duration the annual average cost of customer outages for 1986/1987 for the utilities in the Railbelt region. Also shown in the table is the division in outage costs between residential and non-residential customers.

Table 4-5

COSTS OF CUSTOMER OUTAGES IN THE RAILBELT REGION

	(M$/yr)			(%)		
Utility	Residt'l	Ind/Comm	Total	Residt'l	Ind/Comm	Total
AMLP	0.24	4.57	4.80	4.92	95.08	100.00
MEA	0.68	1.87	2.55	26.72	73.28	100.00
HEA	0.17	1.69	1.86	9.03	90.97	100.00
SES	0.07	0.81	0.88	7.92	92.08	100.00
FMUS	0.03	0.78	0.81	3.28	96.72	100.00
GVEA	0.15	1.93	2.08	7.41	92.59	100.00
CVEA	0.01	0.17	0.18	3.38	96.62	100.00
CEA	0.75	3.60	4.35	17.18	82.82	100.00
Total	2.09	15.42	17.50	11.95	88.05	100.00

Note: The costs shown are calculated using the average historical outages in 1986/1987.

4.3 VALUE OF IMPROVED SYSTEM RELIABILITY

In Table 4-6 we summarize the unserved energy that the proposed 138 KV interties are expected to save. In Table 4-7 we have applied the unit costs of outages to the unserved energy to estimate the value of the unserved energy that would be saved.

Table 4-6

UNSERVED ENERGY SAVED
(MWh/year)

	KA138 LOW	KA138 HIGH	AF100	AF138
KENAI	70.15	94.56	0.00	0.00
ANCHORAGE	30.00	60.00	20.88	20.88
FAIRBANKS	0.00	0.00	0.00	12.14
TOTAL	100.15	154.56	20.88	33.02

Table 4-7

VALUE OF SAVED UNSERVED ENERGY
(millions 1990 $/year)

	KA138 LOW	KA138 HIGH	AF100	AF138
KENAI	1.26	1.69	0.00	0.00
ANCHORAGE	0.50	1.00	0.26	0.26
FAIRBANKS	0.00	0.00	0.00	0.33
TOTAL VALUE	1.76	2.69	0.26	0.58

To calculate the net present value of the saved unserved energy for the KA138 intertie, we assume a 40-year life for the intertie (see Section 2 of this report) and a discount rate of 4.5 percent. The net present value of the saved unserved energy for the KA138 low case is $32.3 million and for the KA138 high case is $49.6 million (in 1990 dollars).

To calculate the new present value of saved unserved energy for the Anchorage-Fairbanks proposals, we assume a 50-year life for the intertie (see Section 2 of this report) and a discount rate of 4.5 percent. The net present value of the saved unserved energy for the AF100 upgrade is $5.0 million. The net present value for the saved unserved energy for the AF138 intertie is $11.5 million.

The value of improved system reliability is the value of the avoided cost of unserved energy unless the same level of reliability can be achieved for less cost. For the Railbelt, an alternative means of achieving the same reliability as the proposed interties is to maintain a higher level of spinning reserves. If the cost of increasing spinning reserves to achieve the same level of reliability as the interties is less than the value assigned to the saved unserved energy, then the value of the level of reliability is the cost of the equivalent spinning reserves.

In the Reconnaissance Study we estimated the cost of maintaining one additional megawatt of spinning reserves to be on the order of $80,000 (1000 KW/MW x 8760 hours/year x 0.005 MBtu/KWh x 1.8 $/MBtu). Our revised analysis of spinning costs in the Railbelt (see Section 7) indicates that the cost of maintaining one megawatt of spinning reserves to be on the order of $112,000 (1000 KW/MW x 8760 hours/year x 0.007 MBtu/KWh x 1.8 $/MBtu). At this cost, it is unlikely that the spinning reserve approach would produce a lower estimate of the value of improved service reliability.

Table 4-8 summarizes the present value of the reliability benefits for each of the intertie proposals.

Table 4-8

PRESENT VALUE OF RELIABILITY BENEFITS

	$1990 Millions
KA138 Intertie (Low Case)	32.33
KA138 Intertie (High Case)	49.58
AF100 Upgrade	5.04
AF138 Intertie	11.52

4.4 REFERENCES

[1] "Value of Service Reliability to Customers," EPRI Report EA-4494, prepared for EPRI by Criterion, Incorporated, San Diego, CA, May 1986.

[2] L. V. Scott, "Ontario Hydro Surveys on Power Systems Reliability: Summary of Customer Viewpoints," compiled in *The Value of Service Reliability to Consumers*, EPRI Report #EA-4494, May 1986.

[3] "Customer Demand for Service Reliability: Existing and Potential Sources of Information," prepared for EPRI by Laurits Christensen Associates, Madison, Wisconsin, May 1989.

[4] A. P. Sanghvi, "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience," *The Value of Service Reliability to Customers*, EPRI, EA-4494, May 1986.

[5] Scott op. cit.

Section 5

ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS OF THE INTERTIE ALTERNATIVES

5.1 OVERVIEW

This section describes the benefits that the AF100, AF138, and KA138 intertie options provide in terms of increased economy energy savings and decreased transmission losses. We cover these benefits together in this section since they are closely related. The economy energy and transmission loss savings were simultaneously analyzed using the Over/Under production simulation model.[1] A number of adjustments were subsequently made to the Over/Under results as follows:

1. For the AF100 and AF138 options, an adjustment was made to account for the North Pole operating constraint (refer to Section 5.2).

2. For the KA138 intertie, an adjustment was made to account for the increased transfer levels that (a) would be appropriate considering the part-load performance of thermal units, and (b) are not recognized in the Over/Under simulation (refer to Section 5.2).

3. For all intertie options, an adjustment was made for the benefits from the collection of gas royalty and severance taxes (refer to Section 5.2).

The results of this analysis show that the benefits to be gained within these categories for all three options are substantial. The benefits between Anchorage and Fairbanks are primarily due to the large disparities in marginal power production costs in those two areas, and because the optimal power flow across the line exceeds its present capacity during periods of heavy demand. The optimal power flow is projected to exceed the capacity of the existing line more often in the future. The benefits of both the AF138 and the AF100 options are due, for the most part, to alleviating the capacity constraint of the existing line. The benefits of the new Kenai-Anchorage line are almost entirely due to increased hydro-thermal coordination.

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1. The Over/Under model is a long-term capacity expansion/production simulation model that was developed by Decision Focus Incorporated for the Electric Power Research Institute.

5.2 INTRODUCTION

5.2.1 Increased Economy Energy Benefits

Economy energy benefits are realized when an intertie allows energy transferred from a lower-cost area to displace energy that would otherwise be produced in a higher-cost area. Increases in transmission capacity can provide opportunity for additional economy energy savings. For example, if an existing line allows 200 GWh per year of cost-effective transfers between the two areas and a new line expands this opportunity to 300 GWh per year, then the new line allows the transfer of an additional 100 GWh per year of economy energy and therefore provides opportunity for additional savings.

5.2.2 Reduced Transmission Loss Benefits

Reduced transmission loss benefits occur because of more efficient interties. For example, if 40 GWh per year of losses are incurred over an existing line, and 10 GWh per year are incurred with a new line, then the new line provides transmission loss savings equal in value to the cost of producing 30 GWh per year.[2]

5.2.3 North Pole Operating Constraint

The "North Pole operating constraint" occurs because the poor part-load performance of the North Pole oil-fired combustion turbines in Fairbanks mandates that, for economic reasons, the units are always operated above a certain minimum load level. When the demand in Fairbanks for energy over the intertie exceeds the intertie capacity, one of the North Pole units must be started. Because the minimum economic level of operation of these units is relatively high, intertie purchases must be reduced substantially whenever a North Pole unit is started, even if demand exceeds intertie capacity only slightly. The Anchorage-Fairbanks intertie options would reduce or eliminate this North Pole constraint by allowing a higher level of energy imports into Fairbanks from Anchorage. As a result, there would be fewer occasions for which a North Pole unit would be started up.

The benefit calculations for the Anchorage-Fairbanks intertie alternatives are based on the assumption that the North Pole units are normally operated only when intertie capacity added to existing and economic coal-fired capacity is insufficient to meet Fairbanks load. If North Pole units were operated for significant periods to provide improved reliability or improved electrical conditions in the area, even when

2. However, if substantially more energy flows over the line because it is more efficient or has greater capacity, it is possible that total transmission losses would actually increase. An increase in total losses would reduce the benefit of increased economy energy transfers.

intertie capacity is sufficient, then the benefits of the intertie alternatives would be lower than we have estimated.

5.2.4 Benefits of Increased Hydro-Thermal Coordination

The Kenai-Anchorage transfers estimated by the Over/Under model were adjusted to account for part-load performance characteristics of thermal power plants based on improved hydro-thermal coordination. Significant benefits can be achieved by scheduling the energy production of a hydro resource in order to minimize the part-load operation of thermal units elsewhere in the system. Thermal units are much more efficient at full load than at part load. The idea is to schedule the hydro energy in a way that minimizes part-load operation of thermal units and maximizes their full-load operation. The Over/Under simulation is not sufficiently detailed to capture this possibility, so an adjustment was calculated to estimate the additional transfers between Kenai and Anchorage that would achieve the optimal coordination of hydro units on the Kenai and thermal units in Anchorage. Benefits of the new intertie are increased to the extent that existing line characteristics limit these additional transfers.

5.2.5 Benefits from Increased Gas Royalty

The new Anchorage-Fairbanks intertie would allow increased gas substitution for oil and, therefore, would increase the State's royalty and severance tax. This benefit is not accounted for in the Over/Under simulation. To calculate the benefits from the gas royalty, we assume a royalty of 18 percent of the well-head gas price. The gas royalty benefit is calculated as a straight percentage of the increase in gas use attributed to the interties. We adjust for reduced benefits in later years when the gas supply is depleted.

5.2.6 Modeling Approach

In performing this analysis, we constructed a representation of the Railbelt generation and transmission system in the Over/Under model and simulated system operation under various fuel price and load conditions. The initial modeling year was set at 1994 since most of the alternatives could not be brought on-line before then. The Kenai-Anchorage intertie was subjected to the same set of inputs for the 40-year period from 1994 to 2033. The Anchorage-Fairbanks intertie alternatives were subjected to the same set of alternatives for the 50-year period from 1994 to 2038.[3]

3. For more details on the economic life of a line refer to Section 2.

Electricity demand and fuel prices are assumed constant between 2010 and 2038 due to the heightened uncertainty associated with distant time frames. Total system costs under each set of assumptions were computed in 1990 dollars for each year and discounted back to 1994. Significant modeling assumptions are presented in Appendix B of this report. For more details on the methodology used for multi-area production simulation and the calculation of adjustments associated with the North Pole operating constraint, refer to the Reconnaissance Study, Appendix E.[4] The adjustment of Kenai-Anchorage transfers based on improved hydro-thermal coordination is described in Appendix A of this study.

The three intertie options examined in this section are as follows:

1. A new Kenai-Anchorage 138 KV line with input transfer capacity equal to 150 MW (labelled "KA138").

2. A limited upgrade of the Anchorage-Fairbanks line to an input transfer capacity of 110 MW (labelled "AF100").

3. A limited upgrade of the Anchorage-Fairbanks line with a new 138 KV line from Healy to Ft. Wainwright with an input transfer capacity between 120 MW and 140 MW.[5]

5.3 ALTERNATIVE CASE SCENARIOS

5.3.1 Fuel and Load Forecast Scenarios

A set of base case scenarios were developed for the combination of three fuel-price and three load-forecast assumptions. These forecasts are the same forecasts used in the Reconnaissance Study.[6] In this study, no attempt has been made to weight the different fuel and load forecast scenarios. Where average values are calculated, each scenario is treated as equally likely.

4. Refer to "Railbelt Intertie Reconnnaissance Study: Benefits/Cost Analysis," prepared by Decision Focus Incorporated for Alaska Power Authority, May 1989.

5. See Section 5.3.

6. The fuel price forecasts are discussed in Appendix B, and the load forecasts are discussed in Appendix C of the Reconnaissance Study.

5.3.2 Intertie Capacity Scenarios

Two cases of the economy energy and transmission loss benefits were evaluated. Case 1 assumes the following transfer limits:

	Input (MW)	Output (MW)
Kenai-Anchorage		
• Existing 115 KV Line	70	61
• With Second 138 KV Line (KA138)	150	110
Anchorage-Fairbanks		
• Existing Line	77	62
• With Limited Upgrade (AF100)	110	84
• With Second 138 KV Line (AF138)	120	99

Case 2 assumes the following transfer limits:

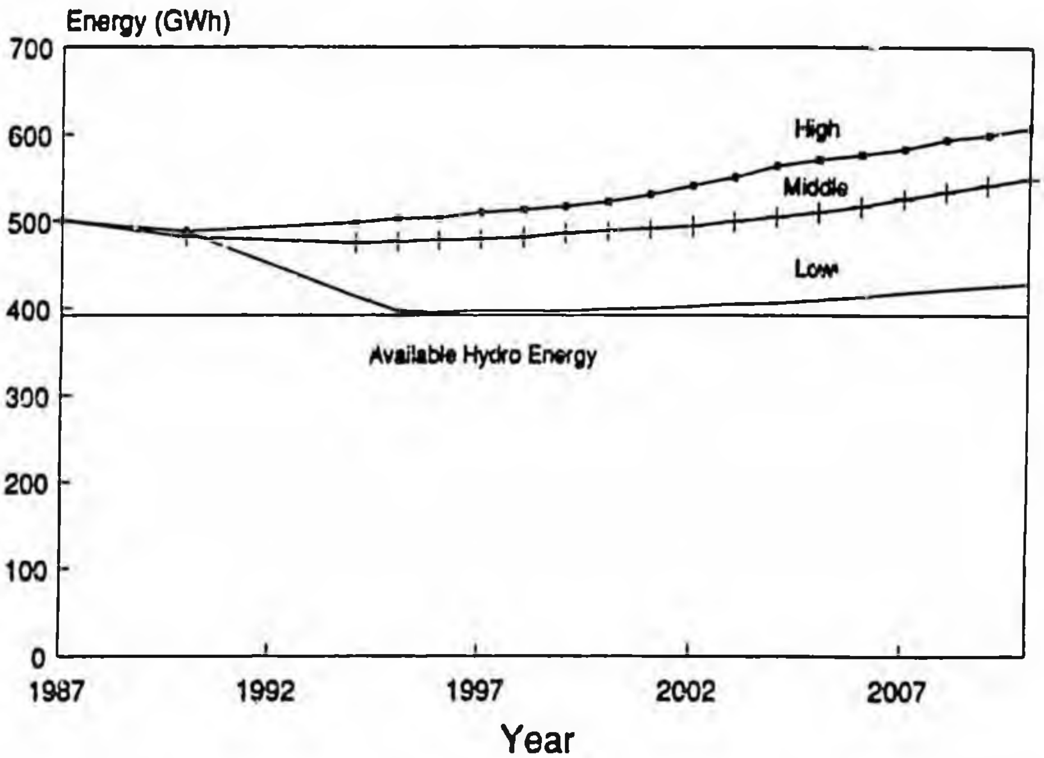
	Input (MW)	Output (MW)
Kenai-Anchorage		
• Existing 115 KV Line	90	75
• With Second 138 KV Line (KA138)	150	110
Anchorage-Fairbanks		
• Existing Line	77	62
• With Limited Upgrade (AF100)	110	84
• With Second 138 KV Line (AF138)	140	112

Both cases were evaluated for each of the fuel and load forecast scenarios.

5.4 ECONOMY ENERGY TRANSFERS BETWEEN KENAI AND ANCHORAGE WITH EXISTING LINE

Gas-fired generating units on the Kenai Peninsula are rarely dispatched in the production simulation. Both Anchorage and Kenai have gas-fired generating units, but Anchorage has combined-cycle and combustion turbine plants that are more efficient than Kenai's combustion turbine generation. The simulation results indicate that little or no economy energy benefit can be gained by regular operation of Kenai gas-fired generation for transfer to the north.

Kenai will have substantial hydro resources after completion of the Bradley Lake project. The available hydro energy over the course of an average year will, however, be less than the anticipated energy requirements of the Kenai Peninsula for all load forecasts (see Figure 5-1). Because there is virtually no variable cost to dispatching available hydro energy, all that potential is used in the production simulation with or without the new line. Because the Kenai gas-fired generation remains more costly than available gas-fired energy in Anchorage, Kenai is a net importer of energy from Anchorage even after Bradley Lake comes on-line. Part of the net annual transfer across the Kenai-Anchorage line is due to this import of energy on the Kenai Peninsula.



Insert Harvard line graph from Recon. Study here.

Figure 5-1. Kenai Load Requirements Versus Kenai Hydro Energy

The main component of anticipated transfers is based on the expected optimal pattern of dispatch from Bradley Lake. Bradley Lake has sufficient storage capability to allow hydro energy production during the winter in excess of Kenai requirements. Further, the hydro resources on the Kenai will have peak generating capacity in excess of Kenai peak demand, which will allow cost-effective transfers from the Kenai Peninsula during certain blocks of time that must then be "paid back" by importing energy from Anchorage during other blocks of time.

The production simulation performed in the Over/Under model captures some of the transfer anticipated due to the pattern of Bradley Lake operation. However, because it is a long-term model that necessarily involves certain simplifications, it does not capture transfers that appear cost-effective as a means of limiting the part-load operation of thermal units in the Anchorage area. The methodology used to estimate these additional transfer levels and transfer benefits is described in Appendix A.

Anticipated transfers between the two areas without the new intertie are shown in Table 5-1 for Case 1 and Case 2. Including the cost-effective transfers estimated to limit part-load operation of thermal units in Anchorage, transfer levels from Kenai to Anchorage in 1994 average 102 GWh per year for Case 1.[7] Transfers from Kenai to Anchorage decline slightly by 2010. Transfers from Anchorage to Kenai in 1994 average 147 GWh per year in the expected case, growing to 217 GWh per year by 2010 due to anticipated load growth on the Kenai Peninsula. As shown, the results for Case 2 do not differ significantly from Case 1.[8] For each case, the transmission losses associated with these transfer levels are also shown.

7. For Case 1, the existing Kenai-Anchorage line has a transfer limit of 613 GWh per year (based on 70 MW x 8760 hours per year).

8. For Case 2, the existing Kenai-Anchorage line has a transfer limit of 788 GWh per year (based on 90 MW x 8760 hours per year).