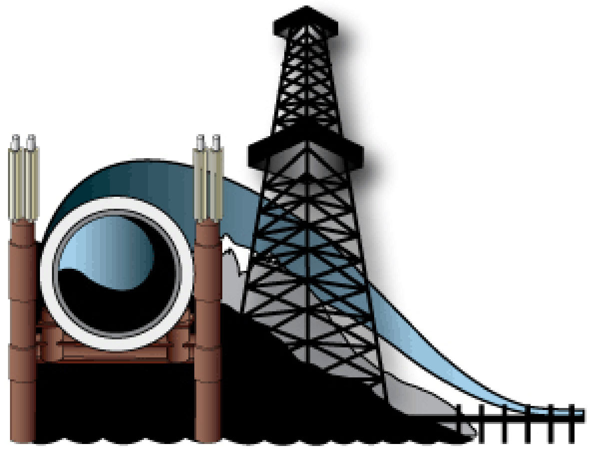

Comprehensive Evaluation and Risk Assessment of Alaska's Oil and Gas Infrastructure

Proposed Risk Assessment Methodology

–Revision 1–

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COMPREHENSIVE EVALUATION AND RISK ASSESSMENT OF ALASKA'S OIL AND GAS INFRASTRUCTURE PROPOSED RISK ASSESSMENT METHODOLOGY

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronyms and Abbreviations	
AAC	Alaska Administrative Code
ABS	American Bureau of Shipping
ALA	American Lifelines Association
ADEC	Alaska Department of Environmental Conservation
AKOSH	Alaska Occupational Health and Safety
AOGCC	Alaska Oil and Gas Conservation Commission
AOGA	Alaska Oil & Gas Association
API	American Petroleum Institute
APL	Alpine Pipeline
APSC	Alyeska Pipeline Service Company
ARA	Alaska Risk Assessment
ARSC	Alternate Route Communications System
AST	Above-Ground Storage Tank
ASTM	American Society for Testing of Materials
AVG	Average
AVO	Alaska Volcano Observatory
BBL	barrel
BLM	Bureau of Land Management
BOE	Barrels of Oil Equivalent
BOPD	Barrels of Oil Per Day
BPXA	BP Exploration Alaska
BWT	Ballast Water Treatment
CCP	Central Compressor Plant
CCPS	Center for Chemical Process Safety
CD	Central Drillsite
CFR	Code of Federal Regulations
CGF	Central Gas Facility
CIGGS	Cook Inlet Gas Gathering System
CIPL	Cook Inlet Pipeline
CIRCAC	Cook Inlet Regional Citizens' Advisory Council
CONCAWE	Conservation of Clean Air and Water in Europe
COTU	Crude Oil Topping Unit
CPAI	ConocoPhillips Alaska, Inc.
CPF	Central Processing Facility
CPS	Central Power Station
DOL	Department of Labor
DOR	Department of Revenue
DOT	Department of Transportation

Acronyms and Abbreviations	
DRA	Drag Reducing Agent
EGIG	European Gas Pipeline Incident Data Group
EiReDA	European Industry Reliability Data
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPRD	Electronic Parts Reliability Data
EOA	Eastern Operating Area
ESA	Environmentally Sensitive Area
FARADIP	Failure Rate Data In Perspective (FARADIP)
FS	Flow Station
FMD	Failure Mode/Mechanism Distribution
FMEA	Failure Modes and Effects Analysis
GC	Gathering Center
G&I	Grind and Inject
GIDEP	Government-Industry Data Exchange Program
GINJ	Gas Injection
GPB	Greater Prudhoe Bay
GPMA	Greater Point McIntyre
GVEA	Golden Valley Electric Association
HazID	Hazard Identification
HSE	Health, Safety and Environment
HSEMS	Health, Safety and Environmental Management System
IEEE	Institute of Electrical and Electronics Engineers
IM	Integrity Management
IPA	Initial Participating Area
JPO	Joint Pipeline Office
KKPL	Kenai-Kachemak Pipeline
KPL	Kuparuk Pipeline (or Kenai Pipeline)
KUTP	Kuparuk Unit Topping Plant
kW	Kilowatt
LDF	Large Diameter Flow Line
LNG	Liquefied Natural Gas
LPC	Lisburne Production Center
M	Thousand
MM	Million
MechRel	Handbook of Reliability Prediction for Mechanical Equipment
MGS	Middle Ground Shoal
Mi	Mile
MI	Miscible Injectant
MMS	Minerals Management Service
MOC	Management of Change
MPI	Main Production Island

Acronyms and Abbreviations	
MRU	Mainline Refrigeration Unit
Mscf	Thousand Standard Cubic Feet
MW	Megawatt
N/A	Not Applicable
NAEC	Northern Alaska Environmental Center
NAS	National Academy of Sciences
NFPA	National Fire Protection Association
NGL	Natural Gas Liquid
NGO	Non-Governmental Organization
NH	Natural Hazard
NPRD	Non-electric Parts Reliability Data
NRC	National Research Council
NSB	North Slope Borough
OCC	Operations Control Center
OREDA	Offshore Reliability Data
OSHA	Occupational Safety and Health Administration
PA	Participating Area
PERD	Process Equipment Reliability Data
PFD	Process Flow Diagrams
PHMSA	Pipeline and Hazardous Materials Safety Administration
P & ID	Process and Instrumentation Diagrams
PMP	Project Management Plan
POC	Point of Contact
PPE	Personal Protective Equipment
PS	Pump Station
PSI	Pounds per Square Inch
PSIO	Petroleum Systems Integrity Office
PSM	Process Safety Management
PWS	Prince William Sound
PWSRCAC	Prince William Sound Regional Citizens’ Advisory Council
QA	Quality Assurance
QC	Quality Control
QRA	Quantitative Risk Analysis or Assessment
RCAC	Regional Citizen’s Advisory Council
RFP	Request for Proposal
RGV	Remote Gate Valve
RIAC	Reliability Information Analysis Center
ROV	Remotely Operated Valve
SAOT	State Agency Oversight Team
SDI	Satellite Drilling Island
SIP	Seawater Injection Plant
SOW	Scope of Work

Acronyms and Abbreviations	
SPIDR	System and Part Integrated Data Report
SR	Strategic Reconfiguration
STP	Seawater Treatment Plant
TAPS	Trans Alaska Pipeline System
UAA	University of Alaska Anchorage
UAF	University of Alaska Fairbanks
UKOPA	United Kingdom Onshore Pipeline Operators' Association
UPS	Uninterruptible Power Supply
USAF	United States Air Force
USDOT	United States Department of Transportation
UST	Underground Storage Tanks
VMT	Valdez Marine Terminal
VSM	Vertical Support Member
WBS	Work Breakdown Structure
WDSP	Water Disposal
WINJ	Water Injection
WTRSP	Water Supply
WOA	Western Operating Area

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1 EXECUTIVE SUMMARY

The proposed risk assessment methodology specifies the process that will be used to assess Alaska oil and gas production infrastructure during Phase 2 of the Alaska Risk Assessment (ARA) Project. This report presents the methodology by which Alaska oil and gas infrastructure facilities, systems, and components with the highest threats of failure and highest potential consequences to the safety of the public and industry workers, the environment, and production, which contributes approximately 85% of the State's total revenue, will be assessed.

The methodology presented in this report describes a series of systematic steps that begins with defining the physical scope of the infrastructure, which will be partitioned into manageable segments, or nodes, for analysis. Following the segmentation process, preliminary screening of each node will be performed, and nodes that do not have the potential to create significant consequences will be eliminated from further risk analysis. Nodes that are identified during preliminary screening as having the potential to create significant consequences will be carried forward and will undergo a concurrent detailed analysis of both operational and natural hazards. The operational hazards assessment will involve estimating the infrastructure risks that can be attributed to equipment failures due to mechanical failures and human error. The natural hazards assessment will supplement the operational hazards assessment and help estimate the risk contribution to the infrastructure as a result of natural hazard events. The results of the risk assessment will then be summarized in the form of a risk profile. For each risk class (safety, environmental, reliability), the risk contributions from the nodes will be totaled to estimate the overall infrastructure risk. Additionally, the larger nodal contributors to each risk class will be identified. The final step of the assessment will be to document assumptions, data, and risk results in a manner that supports the State in its effort maintain or lower the identified infrastructure risks. The risk results, major risk contributors, and the characteristics of the nodes that present high risk (e.g., locations, types of materials, primary failure mechanisms, etc.) will be documented.

The proposed risk assessment methodology will be evaluated by the State, the public, and an independent third-party reviewer prior to finalization.

Methodology Inputs

The methodology presented in this report was developed based on best risk assessment practices combined with insights and information gained during the first part of Phase 1 of the project. In addition to existing information and data review activities, Phase 1 included a comprehensive stakeholder consultation process to obtain key stakeholder input into the scope and methodology for the ARA. Information and data developed during Phase 1 has been documented in the Interim Report issued January 16, 2009.

Numerous risk assessment tools, processes, and standards were considered for use in this project based on the Task 1 document reviews, continuing research to support methodology development, as well as professional experience. The following operational hazards assessment and natural hazards assessment approaches were reviewed and selected for the methodology:

- *Operational Hazards Assessment* – Hazard Identification (HazID) techniques, event tree analyses, what-if analyses, consequence analysis methods (e.g., modeling for releases, fires, explosions), and failure modes and effects analyses (FMEAs) will be used (see Sections 6 and 7).

- *Natural Hazards Assessment* – The primary basis will be the American Lifelines Association (ALA) Guidelines, a consensus document based on industry and government efforts to develop and document natural hazard assessment techniques (see Section 8).

Other inputs to the methodology development included the following:

- *Integrity Management Standards and Practices* – System integrity efforts are designed to address failure mechanisms or factors that contribute to pipeline and other equipment failures, and were an important consideration in the methodology development.
- *Comparable Risk Assessment Related Projects* – Comparisons of publicly available large scale and complex risk assessment projects, as well as Alaska infrastructure projects, were made in terms of similarity of objectives, scope, and applicability to current infrastructure.
- *Stakeholder Input* – Stakeholder input from a wide variety of groups and regions including state agencies, federal agencies, local governments, NGOs, native organizations, and the public, has been incorporated into the proposed methodology in order to augment general risk assessment best systematic practices and to align the methodology with the general stakeholder themes that are common across the scope of the oil and gas production infrastructure in Alaska. Stakeholders provided input on initiating events and significant consequences, as well as data source recommendations that have been used to customize the proposed operational hazards and natural hazards assessments. Concerns relating to the three major infrastructure regions of the risk assessment, 1) the North Slope, 2) Cook Inlet, and 3) the Trans Alaska Pipeline System (TAPS) were identified during this process.

Physical Infrastructure Scope

The Physical Infrastructure Scope, described in detail in Section 4, has been defined to establish the parts of infrastructure that are included within the physical scope of the project. A comprehensive list of in-scope facilities and major components for the three infrastructure regions was developed for each operating area considered to be in the scope of the risk assessment for the North Slope, Cook Inlet, and TAPS. The information included is summarized from a master data record that was developed to capture and organize the infrastructure facilities and associated components within the scope of the project.

In general, for the North Slope and Cook Inlet, the project scope begins at the wellbore of the production or service well and does not include issues associated with reservoirs, formations, and associated down-hole production. For all three regions, the scope ends at the point of delivery, and does not include downstream infrastructure or distribution systems. The major infrastructure components are summarized below and described in greater detail in Section 4:

- *North Slope*: Production facilities and pipelines that deliver oil to Pump Station 1 in Prudhoe Bay; including components in the following North Slope units: Kuparuk River Unit, Colville River Unit, Milne Point Unit, Oooguruk Unit, Prudhoe Bay Unit, Duck Island Unit/Endicott, Northstar Unit, Badami Unit. Pipelines common to multiple units and facilities are also included.
- *Cook Inlet:* 16 offshore oil and gas production platforms, 5 onshore production/processing facilities providing platform support, numerous onshore central oil and gas production facilities, the Drift River Terminal facility, and pipelines.
- *TAPS:* The pipeline and facilities that deliver oil from Pump Station 1 (PS 1) to the Valdez Marine Terminal (VMT), including the Trans Alaska Pipeline, the fuel gas line from PS 1 to PS 4, pump stations, and the VMT, up to the marine terminal loading arms.

Risk Assessment Organizational Structure and Data Management

The oil and gas infrastructure will be partitioned into manageable segments, or nodes, for analysis purposes. A node consists of a system or a set of components or equipment that is part of a facility located in a defined geographic location. The amount of equipment in a node may vary from one singular component or major piece of equipment to many components in a system that work together to perform a singular function or process.

The geographic location of a singular node may encompass a small local area around a facility, a few acres, or dozens of square miles. Process material contained in the equipment, proximate worker and public populations, and local environmental sensitivity are factors that will be considered in creating nodes for some facility systems. The organization of the risk assessment and the infrastructure breakdown into segments is described in further detail in Section 5.

During the analysis process, hundreds of scenarios will be documented to address both the operational and natural hazards that are applicable to each piece of the infrastructure. The data used to perform the analysis and the results will be managed and maintained in a customized project database using a Microsoft Access® type platform.

Facilities in the North Slope, Cook Inlet and TAPS regions will first be categorized by type. North Slope facilities can be categorized as one of three different types: *central oil and gas*, *gas handling*, and *support* facilities. Cook Inlet facilities include *offshore oil and gas production platforms*, *onshore central oil and gas processing facilities*, and the *terminal facility*. TAPS facilities include the *pump stations* and the *VMT*.

Facilities will be segmented into major components/systems for the analysis, based on the functions or processes of the individual facility type. Pipelines in the North Slope and Cook Inlet may require pipeline segmentation for longer, subsea or cross-country pipelines which have specific isolatable pieces and may cover large distances. The TAPS pipeline will be divided into segments for nodal analysis based on the segments between pump stations, and as appropriate, factors such as the ability to isolate the section, environmental sensitivity of the area, anticipated spill response measures for the area, the type of line (above or below ground), and natural hazards applicability to the region or local area.

The use of a nodal analysis is very common practice for conducting risk assessments and for maintaining organization in the execution and documentation of a study of such large magnitude. The nodal approach is a sequential and methodical way of examining all potential initiating events or failures that can occur anywhere in the overall "system of systems." Application of this nodal approach addresses the initiating events or failures that occur within a singular node while considering the consequences or impacts of such an event on a system-wide scale. This is commonly referred to in terms of assessing "Global Consequences." The risk assessment will include the documentation of all of the credible consequences from a single node initiating event as they cascade through the entire scope of the oil and gas infrastructure, considering the consequences in both the upstream and downstream affected nodes. This concept of "consider local causes, but account for global consequences" is a commonly implemented approach for a wide variety of risk assessment projects.

Preliminary Infrastructure Risk Screening

Preliminary risk screening is a common risk assessment methodology used to focus risk assessment resources on the most significant population of nodes. A Preliminary Infrastructure Risk Screening of each node will be performed after the infrastructure has been organized into specific nodes (Section

6). Nodes that do not have the potential to create significant consequences will be eliminated from further risk analysis. The screening process and criteria described in Section 6 will be used to postulate worst case credible events for each node such as equipment failures due to mechanical breakdown, human error, or natural hazards, and will conservatively estimate the potential consequence for the following three types of risk categories to be evaluated:

- *Safety Consequences* – Potential safety impacts to both infrastructure workers (occupational) and to members of the public.

  Note: *The categories that have been defined in Section 6 for safety consequences 1) reflect the purpose of this risk assessment as chartered by the State; i.e., to examine catastrophic level events that are potentially high risk which could result in severe or significant consequences, and 2) recognize the large quantity of resources that are already dedicated to protecting the workers and members of the public from accidents that involve the oil and gas infrastructure. Less severe safety threats to workers and the public are already managed by regulations and extensive corporate safety/risk management programs.*

- *Environmental Consequences* – Loss of containment/spill events that have the potential to create adverse effects on the external environment.

- *Reliability Consequences* – Unexpected loss of revenue to the State from unplanned outages of oil and gas production.

Categories have been developed for each of these consequences. If the node has a potential consequence greater than the bottom (lowest) category for a given type of consequence (i.e., safety, environmental, reliability) the node will be carried forward into the detailed risk analysis for that type of consequence. If the node does not have a potential consequence greater than the bottom (lowest) category for any of the three risk types, the node will be excluded from further risk assessment activities since it would not have the potential to result in significant consequences.

Operational Hazards Risk Assessment

The operational hazards assessment involves estimating the infrastructure risks that can be attributed to equipment failures from mechanical failures and human errors. Failure modes will be identified for equipment in those nodes that could potentially have significant impacts, as identified by the preliminary screening of infrastructure (Section 6). For these particular equipment failure modes, data will be gathered from published references and from meetings or workshops with owners/operators of the infrastructure. The data will be combined using applicable statistical methods, and a failure frequency will be estimated.

The consequences of each scenario (i.e., the impact on safety, the environment, and system reliability) will be calculated using material release rate models, material dispersion models, fire and explosion models, safety impact models, release isolation time and equipment repair/restoration time data (which must both be collected from the owners/operators), an environmental impact model, and production interruption information. The combinations of equipment failure frequencies and consequences (safety effects, environmental impact, and production loss) will be used to estimate risk for the node (see Section 7).

Operational hazards that will be considered in this portion of the risk assessment include the following types of hazards that were identified in Phase 1 of the project:

- Fires and explosions (which can result from hydrocarbon releases)
- Spills and leaks (e.g., due to natural aging process – corrosion, abrasion, wear and fatigue)
- Equipment malfunctions

- Loss of infrastructure support systems (e.g., power)
- Changes in process conditions (e.g., composition– heavy oil, increased quantities of solids produced, and throughput decline)
- Human errors (due to worker fatigue, not following proper procedures, resource availability, etc.)

Safety Risk

The purpose of the safety risk assessment component of the Operational Hazards Risk Assessment is to estimate potential harm to workers on site at infrastructure facilities and to the public in nearby communities. The safety risk calculation will include three major tasks in the proposed methodology: 1) Consequence Analysis – Evaluation of physical effects of incidents on people; 2) Likelihood Analysis – Estimation of incident frequencies; and 3) Risk Calculation – Calculation of risks, which are a combination of likelihood and consequences/impacts, and presentation of results.

Safety consequence analysis is focused on the following issues: 1) The quantity and duration of the hydrocarbon material released; 2) the release distance and form of the released material into the atmosphere; and 3) the final form of the released material. Once the magnitude of the hazardous event has been determined, the potential impact on local operations personnel and/or the public will be determined based on relevant staffing and population data. Modeling of worst-case release events and mitigations to protect people from such incidents will either be obtained from facility siting studies requested from facility owners/operators, or will be performed using software and specific infrastructure and hydrocarbon release data for infrastructure lacking an available facility siting study.

The likelihood analysis is comprised of two consecutive tasks: 1) estimation of the failure frequency (i.e., likelihood of failure) for components followed by 2) analysis of the frequency (i.e., likelihood) of significant hazardous operational events. Generic industry-wide reliability data and facility-specific data will be combined to estimate component failure frequencies specific to Alaska's oil and gas infrastructure, using the Bayesian updating tool. For pipeline segments, the scoring method will also be used. Event tree techniques will then be used to identify and estimate the frequency of operational hazardous event outcomes.

Environmental Risk

Loss of containment of vessels (i.e., tanks, pressure vessels and other types of vessels used for the storage or processing of oil and gas) and pipelines containing liquid will result in a spill on the ground or into water, depending on the location of the spill. The environmental risk assessment component of the Operational Hazards Risk Assessment is focused on the likelihood, size and type of spills of hydrocarbon and seawater streams to the external environment. The process of environmental risk assessment includes significant hazardous operational events that potentially result in significant spill scenarios that have been identified through the FMEA technique.

The environmental consequence analysis will address the numerous contributing factors that are associated with spill impacts. These include 1) sensitivity of the surrounding external environment, 2) composition/type of fluid stream that is released, 3) release quantity or volume of fluid released, and 4) recoverability of spill volume and remediation efficiencies. An environmental consequence score will be calculated for each of the release events that are considered, based on the index values that are assigned in each of the contributing factor categories. Likelihood analysis will be performed similar to the safety likelihood analysis described above. The environmental risk methodology for operational hazard scenarios is based on the likelihood of the spills (i.e., likelihood of equipment failure causing a spill scenario) and the environmental consequence of the resulting spill.

Reliability Risk Assessment

The purpose of the reliability risk assessment component of the Operational Hazards Risk Assessment is to analyze the potential for oil and gas production losses that are significant enough to materially affect state revenue. The model provides an estimate of production outages, defined by barrels of production lost, which can subsequently be used by the State to quantify dollar impacts to the State using the Department of Revenue's (DOR) State Revenue Forecast model at a given point in time.

The reliability risk methodology for operational hazard scenarios is based on the frequency of the initiating event for a scenario, the estimated production impacts, and duration of the event. In the reliability assessment, the first step will be to prepare reliability block diagrams (RBDs) documenting the production process flows. Using the RBDs and other design information, a what-if analysis for the node will then be performed to identify scenarios that result in significant production losses. Scenario frequency estimates will be made that reflect generic industry-wide reliability data, facility-specific data, and engineering judgment. When necessary, event trees will be used to analyze the sequence of failures, operator errors, and other factors that contribute to the scenario occurrence. The level of production impact (e.g. 100% of node flow, 50% of node) and the duration of that impact will be estimated for each scenario selected for analysis, with input from facility operators/owners.

Natural Hazards Risk Assessment

A Natural Hazards Risk Assessment will be performed as a supplement to the operational hazards assessment to estimate the risk of natural hazard events that can cause significant impacts. Natural hazards are phenomena that occur in the environment, external to the oil and gas infrastructure and its operations. Natural hazards include atmospheric, hydrologic, geologic, and wildfire events that, because of their location, severity, and frequency, have the potential to affect the oil and gas infrastructure adversely.

As with the Operational Hazard Risk Assessment methodology, preliminary risk screening will be used to focus risk assessment resources for the natural hazards assessment on the most significant population of nodes. The first step of the natural hazards screening is to identify those natural hazards that are applicable to the node. For each applicable hazard event, the equipment associated with the node will then be reviewed to determine if it is vulnerable to failure for that natural hazard. If the node passes these two screening steps (i.e., a specific natural hazard is applicable and equipment in the node is vulnerable to that hazard), likelihood and damage for the applicable natural hazards will be assessed using a detailed risk assessment model based on industry guidance for natural hazards assessment.

The nodes will be screened against 10 pre-selected natural hazard classes which were developed during Phase 1 based on input from the stakeholder consultation process. The project team's natural hazards experts combined and reorganized these stakeholder recommendations to make up the following classes of natural hazards to be considered as part of the assessment:

- Earthquakes
- Tsunamis
- Volcanoes
- Coastal Erosion
- Permafrost Thawing
- Severe Storms
- Floods
- Severe Currents
- Avalanche
- Forest Fires

The detailed natural hazards assessment methodology is based on consensus procedures developed specifically for natural hazards assessment of oil and gas pipeline systems by the American Lifelines Alliance (ALA). Extensions will be applied to the ALA approach to make it applicable to areas of the Alaska oil and gas infrastructure that are not pipelines or pipeline associated facilities (e.g., offshore platforms), and address natural hazards within the scope of the project that are not currently covered by the ALA guidance.

For those nodes found to have a potential for significant consequence(s) during preliminary screening, and at high exposure for specific natural hazard applicability and vulnerability during natural hazard screening, a more detailed evaluation will proceed. The detailed assessment consists of the following steps: 1) identify and quantify natural hazards, 2) identify and quantify the damage states of nodes, 3) consider existing mitigation measures, and 4) estimate the infrastructure natural hazard risks. Implementation of this methodology will result in the definition of natural hazard scenarios, estimation of the frequency and consequence for those scenarios, and allow natural hazards risks to be included in the project risk profile for the Alaska oil and gas infrastructure.

Due to the large number of different hazards to be considered and the physical scope of the infrastructure to be considered, the general approach will be to implement the Level 1 approaches recommended by the ALA guidelines and comparable approaches (where practical) for infrastructure items not covered by those guidelines.

Risk Assessment Results

Operational and natural hazard assessments will be summarized and presented to the State during the final phase of the ARA Project. The summary will include a discussion of 1) components of the final risk assessment database tools, 2) the three ways data will be summarized for presentation to the State and how these formats might be used by the State in future risk management efforts, and 3) how risks in each of the three consequence categories can be compared.

Risk data from the operational and natural hazards assessments will be compiled into a database of the individual scenarios considered as part of the overall risk assessment. After the risk assessment database is populated, the risk assessment results will be summarized and presented in three different formats that will help the State and other users to visualize the results of the project. The basis for these formats will be “major risk contributors” and “contributing factors.”

Major risk contributors are the individual nodes or groups of nodes that present the most risk. Contributing factors reflect the characteristics of the scenarios or nodes (e.g., locations, component types, failure type) that are common to several relatively important risk contributors. Presentation formats will include:

- **Risk Matrices** – shows the number of events by risk level (based on frequency and consequence) *(Safety, Environmental, and Reliability consequences)*
- **Risk Histograms** – shows total estimated frequency for events assigned to each of the consequence categories *(Safety, Environmental, and Reliability consequences)*
- **Risk Summaries** – shows percentages of safety and reliability risk based on characteristics of the scenario and node. *(Safety and Reliability consequences)* Risk summaries will be provided for the following: Facility, Facility type, Operating area (i.e. North Slope, Cook Inlet, TAPS), Owners/Operators, Natural hazard (when applicable)

A number of risk comparisons can be made using results from this project. Risk for a particular node of the Alaska oil and gas infrastructure is estimated by analyzing the risk of various scenarios involving that node. A specific node may have multiple scenarios that present significant risks. Similarly, a single scenario may result in significant risks in one, two or all three of the classes of consequence of interest specific to this project (i.e., safety, environmental, or reliability risk). Within a single consequence class, different scenarios can be compared by frequency, or consequence, or their estimated risk.

A final ARA report will document the results of the risk assessment. The primary outcome of this project will be a risk profile of the Alaska oil and gas infrastructure that can be used by the State to manage the risk of unplanned oil and gas production outages from significant hazardous events. Such risk management decisions include answering questions such as:

- What risk management initiatives should be pursued?
- What risk management initiatives should not be pursued?
- How much money should reasonably be spent on risk management?
- How should that money be spent to obtain the most value?

2 INTRODUCTION

2.1 Background

The Alaska Risk Assessment (ARA) Project was initiated in response to the 2006 corrosion related pipeline leaks that interrupted a portion of Alaska's North Slope oil production. The project is intended to create a "picture" of the current state of the infrastructure, which will assist the State to fulfill its oversight role in maintaining the integrity of the Alaska oil and gas network while protecting the safety of the people, the environment, and ensuring uninterrupted production, which contributes approximately 85% of the State's annual operating budget total revenue. The project will highlight the infrastructure components with the highest threats of failure and highest consequence of loss. Although many risk assessments of individual Alaska oil and gas infrastructure components have been executed in the past, this type of system-wide assessment has never been conducted.

The proposed risk assessment methodology presented in this report was developed based on best risk assessment practices combined with insights and information gained during the stakeholder consultation portion of the project.

Stakeholder communication and outreach were major sources of input during execution of the initial project tasks. Stakeholders from a wide variety of groups and regions were consulted including state agencies, federal agencies, local governments, NGOs, native organizations, and the public. Concerns relating to the three major infrastructure regions of the risk assessment, 1) the North Slope, 2) the Cook Inlet, and 3) the Trans Alaska Pipeline System (TAPS) were identified during this process. In addition to stakeholder consultation, a substantial list of publicly available documents was identified and reviewed. This list included maps, data, reports, state agency statistics, and other publicly available information needed to define the physical scope of the risk assessment.

This proposed risk assessment methodology will be evaluated by the State, the public and independent third-party reviewer National Academy of Sciences (NAS) prior to finalization. The NAS is an honorific society that provides a public service by working outside the framework of government to ensure independent advice on matters of science, technology, and medicine. [1] The NAS will enlist a committee of the nation's top scientists, engineers, and other experts, all of whom volunteer their time to study specific concerns; this committee will review the methodology in accordance with NAS's established internal peer review process.

2.2 Overview of Proposed Methodology

The proposed methodology for the Alaska Oil & Gas Infrastructure Risk Assessment includes the following five activities as shown in Figure 2-1:

1. Infrastructure Physical Scope and Node Definition
2. Preliminary Infrastructure Risk Screening
3. Risk Analysis (Operational Hazards Assessment and Natural Hazards Assessment)
4. Risk Analysis Summary
5. Risk Analysis Documentation

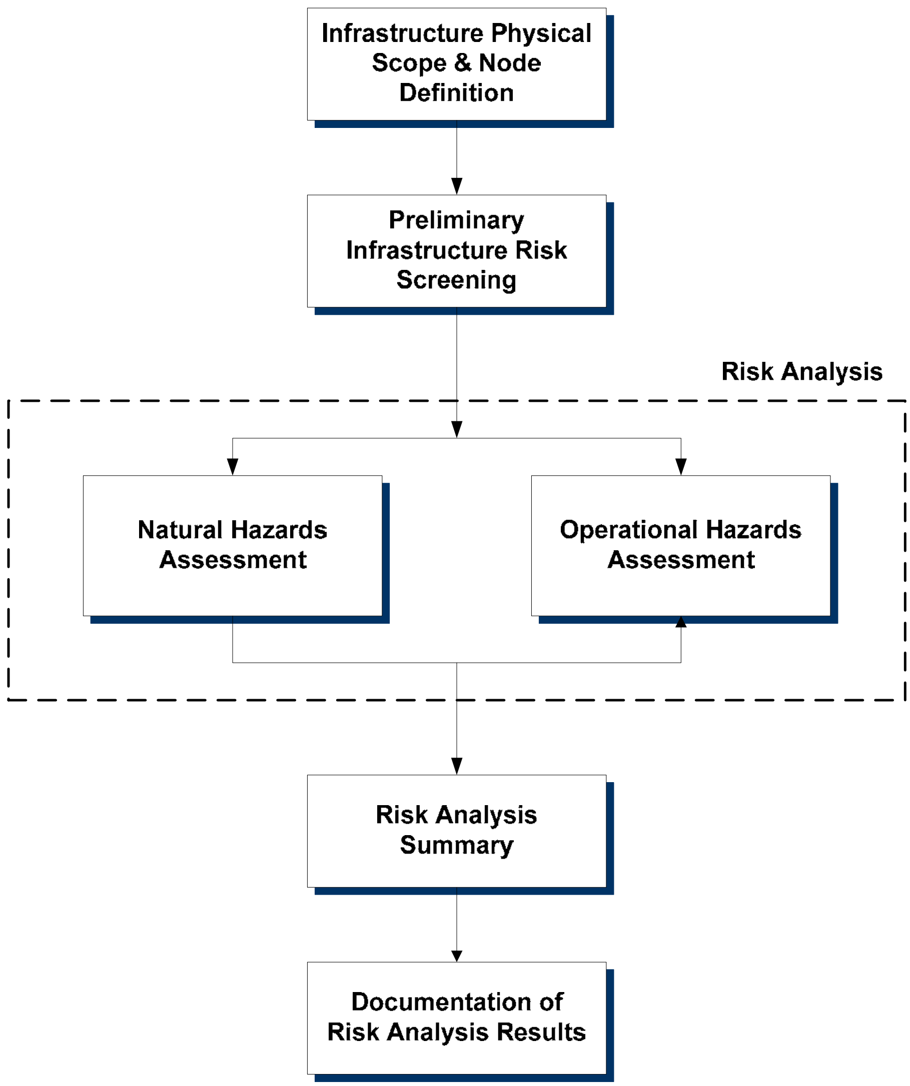

Figure 2-1 Proposed Risk Assessment Methodology Process

2.2.1 Infrastructure Physical Scope and Node Definition

The Infrastructure Physical Scope and Node Definition (Activity 1) establishes the parts of the infrastructure that are included within the physical scope of the project and determines the types of risks to be evaluated. The scope of work, as defined by the State per the contract requirements, identifies in broad terms the physical assets to be considered. The physical assets are defined in greater detail in Section 4 of this report.

The oil and gas infrastructure will be partitioned into manageable segments, or nodes, for analysis purposes. A node consists of a system or a set of components or equipment that is part of a facility which is located in a defined geographic location. The amount of equipment in any node may vary from one singular component or major piece of equipment to many components in a system that work together to perform a singular function or process. The geographic location of a singular node may encompass a small local area around a facility, a few acres, or dozens of square miles. Process material contained in the equipment, proximate worker and public populations, and local environmental sensitivity are factors that will be considered in creating nodes for some facility systems. The organization of the risk assessment and the infrastructure breakdown into segments is described in detail in Section 5.

The use of a nodal analysis is very common practice for conducting risk assessments and for maintaining organization in the execution and documentation of a study of such large magnitude. The nodal approach is a sequential and methodical way of examining all potential initiating events or failures that can occur anywhere in the overall "system of systems." Application of this nodal approach addresses the initiating events or failures that occur within a singular node while considering the consequences or impacts of such an event on a system-wide scale. This is commonly referred to in terms of assessing "Global Consequences." The risk assessment will include the documentation of all of the credible consequences from a single node initiating event as they cascade through the entire scope of the oil and gas infrastructure, considering the consequences in both the upstream and downstream affected nodes. This concept of "consider local causes, but account for global consequences" is a commonly implemented approach for a wide variety of risk assessment projects.

2.2.2 Preliminary Screening

A Preliminary Infrastructure Risk Screening (Activity 2) of each node will be performed after the infrastructure has been organized into nodes. Nodes that do not have the potential to create significant consequences will be eliminated from further risk analysis. The screening process and criteria described in Section 6 will be used to postulate worst case credible events for each node (e.g., equipment failures due to mechanical breakdown, human error, or natural hazards), and will conservatively estimate the potential consequence for the three types of risk categories to be evaluated: *safety*, *environmental*, and *reliability*. If the node has a potential consequence greater than the bottom (lowest) category for a given type of consequence (i.e., safety, environmental, reliability) the node will be carried forward into the detailed risk analysis for that type of consequence. If the node does not have a potential consequence greater than the bottom (lowest) category for any of the three risk types, the node will be excluded from further risk assessment activities.

2.2.3 Risk Analysis

During Activity 3, a detailed risk analysis of the nodes that are carried forward from the preliminary screening process will be performed. The risk analysis will be performed in two parallel efforts:

- Operational Hazards Assessment
- Natural Hazards Assessment

The operational hazards assessment involves estimating the infrastructure risks that can be attributed to equipment failures due to mechanical failures and human errors. Failure modes will be identified for equipment in those nodes that could potentially have significant impacts of interest. For these particular equipment failure modes, data will be gathered from published references and from meetings or workshops with owners/operators of the infrastructure (if possible). The data will be combined using applicable statistical methods, and a failure frequency will be estimated The consequences of each scenario (i.e., the impact on safety, the environment, and system reliability) will be calculated using material release rate models, material dispersion models, fire and explosion models, safety impact models, release isolation time and equipment repair/restoration time data (which must both be collected from the owners/operators), an environmental impact scoring model, and production interruption information. The combinations of equipment failure frequencies and consequences (safety effects, environmental impact, and reliability impacts) will be used to estimate risk for the node (see Section 7).

A Natural Hazards Assessment will also be performed to help estimate the risk contribution to the infrastructure from natural hazard events that have the potential to cause significant impacts. The nodes will undergo a second screening process which will help to identify both the applicability and the vulnerability of infrastructure components and systems to natural hazard events. The natural hazards screening will be performed against a set of pre-selected natural hazard classes which were developed as part of the input from the stakeholder consultation process and supplemented by natural hazard risk professional judgment. The first step of the natural hazards screening process will be to identify those natural hazards that are "applicable" to the node. For each applicable natural hazard event, the equipment associated with the node will be reviewed to determine if it is vulnerable to failure from that natural hazard, if it were to occur. If the node passes these two screening steps (i.e., a specific natural hazard is applicable and equipment in the node is vulnerable to that hazard), likelihoods and damage for the applicable natural hazards will be assessed based on engineering judgment and comparison of potential impacts to the original design criteria (if available) for the equipment that is being examined and industry recommended practice and guidance for performing natural hazards assessments. Also, specific consequences for natural hazards events that result in safety, environmental, and reliability impacts) will be estimated using the consequence assessment methods discussed in Section 8.

2.2.4 Risk Assessment Summary

In Activity 4 of the risk assessment process, the risk analysis results for each of the nodes will be summarized to estimate the overall risk for the oil and gas infrastructure. For each risk class (Safety, Environmental, Reliability), the risk contributions from the nodes will be totaled to estimate overall infrastructure risk. Additionally, the larger nodal contributors to each risk class will be identified (see Section 9).

2.2.5 Risk Analysis Documentation

The final step in the process (Activity 5) is to document the assumptions, data, and risk results in a manner that supports the State and the infrastructure owners/operators to help them develop recommendations to maintain or lower the identified infrastructure risks. The risk results, major nodal risk contributors, and the characteristics of the nodes that present high risk (e.g., locations, types of materials, primary failure mechanisms, etc.) will be documented to accomplish this task.

3 METHODOLOGY INPUTS

The purpose of this section is to describe the information that has been used to formulate the risk assessment methodology proposed in this report. Most of the information was acquired during the document review and stakeholder consultation processes, which were accomplished during Task 1 of the project. The following topics are discussed:

- Attributes of the ARA project that make it unique in scope, complexity, and structure
- The suitability of various risk assessment tools, processes, and standards for this project
- Other risk assessment projects comparable in scope or complexity and their utility specific to the ARA project methodology
- How stakeholder input received during the consultation period was incorporated into the proposed methodology

3.1 Complexity and Scope of the ARA Project

The physical scope of the ARA Project is larger and more complex than other known oil and gas infrastructure risk assessments that have been conducted. This section describes the factors that contribute to the size and the scope of the project and how that has impacted the methodology development choices made by the team in order to meet both the time and resource limitations of the project. Specifically, the scope of the project is expansive in terms of:

- **Consequence Classes** - The requirement to consider safety, environmental, and reliability risks requires three assessment approaches. Although some assessment efforts are typical for any class of consequence and will be shared, in many cases, the three consequence classes are independent enough to require three separate sets of analysis efforts.
- **Inclusion of Both Operational and Natural Hazards** - Many natural hazards risk assessments of relatively large energy infrastructure systems (e.g., large natural gas pipelines, electrical distribution networks) exist; however, it is not common to combine an overall natural hazards assessment with a broad assessment of operational hazards (not related to the natural hazards) that can occur at the infrastructure facilities (e.g., power plants or gas processing units) within the same project. For this project scope, a detailed assessment of the operational hazards will be conducted to identify the high risk areas of continued operations of the aging infrastructure into the future. The natural hazards assessment will be focused on identifying those key infrastructure components which are vulnerable and the potential individual and overall system risk contributions that are associated with natural hazard events that occur in the three infrastructure regions of the State.
- **Geography** – The Alaska oil and gas production infrastructure encompasses the North Slope, the approximately 800 miles of the TAPS, and onshore and offshore facilities in Cook Inlet. Often risk assessment project personnel need to conduct site inspections of the facilities to collect local data. The approach developed for this project recognizes that onsite data collection must be minimized and data will need to be accessed by working with infrastructure owners/operators or through state agencies.
- **Number of Infrastructure Facilities and Associated Operators** – There are approximately 140 facilities on the North Slope, 65 in the Cook Inlet Region, and 800 miles of TAPS, with 5 pump stations (including 1 relief station) currently operating. These facilities are operated by about 10 different operator organizations, which have different corporate structures and

cultures. This means there are a large group of technical points of contact that will have to be consulted to obtain and/or validate data used in this risk assessment.

3.2 Risk Assessment Tools, Processes, and Standards

A number of risk assessment approaches were considered for use in this project based on the Task 1 document reviews, continuing research to support methodology development, and professional experience. These approaches and the reasoning for their inclusion or exclusion from the project are discussed below in the separate operational hazards and natural hazards subsections. Approaches that were selected for use in the implementation phase of this project are discussed in detail in Sections 7 and 8 of this report.

3.2.1 Operational Hazards Assessment

Various methods were evaluated for use in examining operational hazards for the project. It should be noted that some approaches overlap and include elements of other methods (e.g., fault trees and event trees are tools often used in quantitative risk analysis (QRA)). Approaches considered for the operational hazards assessment include:

- Hazard identification (HazID) techniques
- Fault tree analyses
- Event tree analyses
- Detailed QRA approaches
- Consequence analysis methods (e.g., modeling for releases, fires, explosions)
- Failure modes and effects analyses (FMEAs)
- Availability assessment

HazID techniques include checklist-based assessments and approaches that are based on structured brainstorming techniques. Generally, the objective of these methods is to identify applicable hazards and to define how those hazards might occur. In some cases, HazIDs include frequency and consequence screening approaches. In this risk assessment, HazIDs will be used to identify scenarios for more detailed risk assessment activities.

A scenario-oriented approach will be used to assess operational hazards. This approach uses engineering judgment, results from previous studies, information provided by experts, and simple logic modeling (using event trees when needed) to assess scenario risks. A detailed QRA approach, which models all events in fault tree/event tree models and quantifies all potential event sequences, will not be proposed for scenario evaluation due to the diversity of hazards of interest in this project and the lack of specific data to support detailed quantitative assessments.

Event trees will be used to estimate frequencies and to structure the consequence assessments associated with some scenarios. Whenever possible, "representative event trees" will be applied to groups of scenarios (e.g., a tree for a gas leak that is a significant scenario only if detection and isolation fail) to ensure maximum efficiency in conducting the hazard analysis.

This report describes a detailed availability assessment approach (See Appendix H) because of its potential role in typical reliability assessments. However, it is likely that operators of Alaska's oil and gas infrastructure have addressed such issues in their own studies. Availability issues are unlikely to pose risks that are not already being considered in production schedules and state revenue projections. Tools including FMEAs (for failure mode identification, which is described in more detail in Section 7) and methods used to calculate downtime due to random failures are available to address unique availability issues identified in preliminary screening efforts.

3.2.2 Natural Hazards Assessment

The stakeholder solicitation process in Task 1 of this project identified more than a dozen natural hazards, which have been reorganized and consolidated into the ten natural hazards described in Section 8 of this report. A detailed natural hazards assessment will be conducted as a supplement to the operational hazards assessment and will address these 10 hazards using a unique analysis approach. The natural hazards assessment will assume that the original design and construction of the oil and gas infrastructure in Alaska was executed according to existing design and construction standards and considered the presence of natural hazards in the regions where the infrastructure is located. However, compliance with original design standards does not guarantee that systems will not fail. For example, 1) natural hazards can occur that are more severe than design basis, or 2) system failures can occur even for equipment that is properly designed.

The natural hazards assessment for this project will be focused on a screening process which will help to identify components and systems of high vulnerability within the infrastructure and the resultant potential consequences associated with failures of those components or systems during natural hazard events.

Therefore, in selecting a methodology approach for evaluation of natural hazards for the risk assessment, three basic types of approaches were considered:

1. Application of individual natural hazard methodologies for all of the applicable infrastructure
2. Synthesis of overall natural hazard risk results from individual risk studies performed by infrastructure owners/operators
3. Development of a single, higher level approach for multi-hazard evaluation of the infrastructure

The first methodology approach option is the most time and resource intensive of the three options and was determined to be beyond the time and resource limits associated with the project. Due to the large scope of the infrastructure and based on the project team's experience with other large-scale studies, this approach would not be practical for assessing natural hazards as applied to each of the nodes.

The second methodology approach option would involve obtaining existing natural hazard studies from the infrastructure owners/operators and using them to synthesize a risk profile for the overall infrastructure. This option was also not selected for implementation in this project for the following reasons:

- It is not certain that all of the infrastructure owners/operators have performed such studies for the majority of the classes of natural hazards of interest to this project
- Existing studies are generally considered proprietary by the owners/operators; therefore, it is unlikely that the study results could be directly included in the risk assessment (even if the individual studies are made available to the project)
- Synthesizing comparable results from studies performed by companies with potentially differing objectives would be difficult. Unless the various studies were conducted with a common approach, it is unlikely that consistent evaluation of infrastructure components owned or operated by these different organizations could be ensured.

The third methodology approach was determined to be the best methodology—a higher level natural hazards assessment based on a consistent approach. As a starting point, a set of consensus procedures that was originally developed specifically for risk assessment of oil and gas pipelines (the American Lifelines Association (ALA) guidelines[2] described in Section 8) was elected for use. Although numerous infrastructure risk assessment guidelines exist, they are generally oriented to risk assessment for land use or emergency response planning rather than safety, environmental, and reliability risks.

The natural hazards assessment methodology described in Section 8 is based on a combination of the experience of the team members that will guide the natural hazards implementation and the recommendations provided in the ALA guidelines (see Appendix I). The ALA approach provides methodologies for many of the natural hazards of interest in this project, and is based on industry and government efforts that have developed and documented natural hazard assessment techniques. The ALA approach was developed to address only oil and gas pipelines and will be customized during implementation to include some natural hazards of interest that are specific to this risk assessment. Additionally, the guidelines will be modified to cover assessments of the other types of facilities within the scope of this risk assessment (e.g., North Slope production facilities, Cook Inlet production platforms, and the extensive utility/support systems associated with the Alaska oil and gas infrastructure).

3.3 Integrity Management Standards and Practices

Integrity management standards and practices were reviewed, summarized, and presented in the Interim Report as part of Task 1 of the project. These standards were an important consideration in the development of the proposed methodology and are discussed in Section 7 of this report. Integrity standards pertinent to this project that have been considered in terms of the methodology include:

- Pipeline Integrity Management for Gas Pipelines (49 CFR 192 Subpart O)
- Pipeline Integrity Management in High Consequence Areas - for Hazardous Liquid Pipelines (49 CFR 195.452)
- ASME B31.8S, Managing System Integrity of Gas Pipelines (which is referenced by 49CFR 192)
- API Publication 353, Managing Systems Integrity of Terminal and Tank Facilities
- API 1160, Managing System Integrity for Hazardous Liquid Pipelines

The major threats that system integrity efforts are designed to address generally encompass failure mechanisms or factors that contribute to pipeline and other equipment failures, including:

- Internal corrosion
- External corrosion
- Stress corrosion cracking
- Fabrication or construction defects
- Third party damage
- Outside force damage
- Human error

Like other mitigation measures targeted at reducing the likelihood or impact of a risk, system integrity efforts have the potential to mitigate risks of failures, specifically those listed above. Therefore, the presence and evaluation of the sufficiency of integrity management programs have been incorporated into the detailed operational hazards assessment described in Section 7.

System integrity standards have been under development, promulgation, and initial implementation only within the last eight to ten years. Dates have been established relatively recently for full implementation of the liquid and gas pipeline system integrity regulations applicable to older Alaskan pipelines (i.e., those in service when the new regulations were published). Many of the basic steps of integrity programs have been only recently completed, and multiple cycles of those efforts have not occurred. For failure mechanisms such as fabrication or construction defects, a significant level of risk reduction is probably gained in the initial system integrity program implementation. Multiple cycles of program activities will be required to identify potential threats to integrity that relate to the time-dependent mechanisms of primary concern to the State (i.e., corrosion and erosion).

3.4 Comparable Risk Assessment Related Projects

In Task 1 of this project, a wide range of risk assessment methodology and guidance reports, regulations, and a limited number of specific risk assessment project reports were reviewed. Although it is not apparent that any other risk assessment exists that is comparable in scope and complexity to this project, comparisons can be made to past risk assessments in terms of similarity of objectives, scope, and applicability to current infrastructure. This section highlights those documents that are considered most pertinent to the ARA project.

3.4.1 Other Large-Scale and Complex Risk Assessment Projects

As part of the methodology development process, other large and complex risk assessment related projects were considered. These included both publicly available studies and other studies in which members of the project team have participated. Some of those example studies include:

- *Reactor Safety Study* - an early (i.e., 1975) application of quantitative risk assessment (QRA) to nuclear power plants (public)
- *The Prince William Sound Risk Assessment* (public)
- *Individual Plant Examinations* – QRAs required in the 1980s and 1990s for all U.S. nuclear power plants (public)
- Operational risk assessments of two world-scale Canadian tar sand facilities*
- Numerous risk assessments of refineries in a variety of countries world-wide*
- Navigational risk assessments for a variety of locations (public or proprietary involving project team members)
- Risk assessments of water utilities and suppliers, including a California study that addressed wholesale water supplies to 12 different municipalities*
- A large number of electrical utility generation and distribution natural hazard studies*
- Several pipeline risk assessment studies including natural hazards and/or operational hazards*

**These are proprietary studies in which project team members have been involved.*

Members of the methodology development team for this risk assessment have been involved in many of these studies or have used these studies in developing approaches for risk assessment projects for other clients. Several observations are possible based on the overall risk assessment experience gained through these studies:

- There is never as much failure data as a risk assessment team would like to have, and if there was, the client would not need to have a risk assessment performed, they could simply use their historical records to highlight every area of concern. For this risk assessment, although there have been some events that have gained a great deal of attention, in fact, there have been very few "catastrophic events" involving the oil and gas facilities within the scope of this study.

- Reports that describe risk assessment results should consider multiple audiences. There are many potential users of this particular risk assessment, and it will be important that the report is designed to communicate effectively to different users (e.g., big picture summary, details about specific infrastructure, data/methods so follow-on studies can be performed).
- Risk assessments need to be grounded in real-world experience. Looking carefully at loss experience from the specific infrastructure being analyzed has been a critical part of many of the proprietary petrochemical and refining studies referred to above. Real-world experience will also be used to support this risk assessment.

Lessons such as these have been incorporated into the methodology proposed in this report and in the preliminary implementation discussions with the project team. Although examples provided are large and/or complex to a certain extent, it is not clear that they represent analytical efforts as large and diverse as those required by this project.

3.4.2 Other Alaska Infrastructure Studies

In addition to large and complex risk assessment related projects, the following studies specific to the Alaska infrastructure have been identified and are discussed in more detail in this section:

- Argonne National Laboratories for the Bureau of Land Management. (2002). *Final Environmental Impact Statement - Renewal of the Federal Grant for the Trans-Alaska Pipeline System Right-of-Way*)[3]
- Marine Board of the National Research Council. (1998). *Review of the Prince William Sound, Alaska, Risk Assessment Study*
- Transportation Research Board of the National Academy of Science. (2008). *Risk of Vessel Accidents and Spills in the Aleutian Islands: Designing a Comprehensive Risk Assessment*, 2008. Specifically, the proposed risk assessment for the Aleutian Island vessel accident and spill risk provided important insights and suggestions for the methodology suggested in this report.
- Business Continuity or Availability Assessments by Infrastructure Operators
- Integrity Management Risk Assessments Under DOT Regulatory Requirements
- OSHA Process Safety Management and EPA Risk Management Hazard Analyses

The first three of these bulleted items address individual studies, while the last three are collections of studies that have been performed either for industry risk management activities or as part of regulatory requirements.

It is likely that other risk assessments performed by infrastructure owners/ operators exist but are not publicly available. Such studies would be valuable for use during the implementation phase of this project.

In some cases (as in the wholesale water supply study), the initial screening assessment narrowed the scope of the detailed study to a limited number of natural hazards and operational events. The proposed assessment process for the Aleutian Islands study, titled *Risk of Vessel Accidents and Spills in the Aleutian Islands: Designing a Comprehensive Risk Assessment*, also includes a preliminary screening process (See Section 3.4.2.3). A similar screening process which is consequence based has been proposed as a tool (described in Section 6 of this report) to focus the detailed risk assessment efforts in this project. The ALA guidelines[2] also include natural hazard applicability and vulnerability screening steps that are consistent with this proposed methodology.

3.4.2.1 TAPS Right of Way Renewal Environmental Impact Statement

A unique aspect of the ARA project is that it considers three different classes of consequences: environment, safety, and reliability. The TAPS Renewal EIS is the only past study known to the project team that also addressed all three of these consequence classes.

The study's economic assessment addressed the impact of TAPS operation for three alternatives: 1) a 30-year renewal, 2) a shorter renewal, or 3) no renewal, (which would have resulted in a 2004 end of operation for TAPS). The EIS did not address production interruptions except in terms of an average availability for TAPS operation, which historically has been reported as greater than 98%. The assessment addressed worker and public safety, but the worker safety estimates were based primarily on historical safety performance.

The TAPS renewal EIS was a one-time study and was performed during 2001 and 2002. If the State believes that conditions in the infrastructure are changing in undesirable ways, the period of time since this study was completed may be a factor in its ultimate utility to this project's risk assessment activities. However, it remains a valuable reference document because of historical outage and spill data collected and documented and the analyses regarding future environmental impacts of TAPS operations.

3.4.2.2 Review of the Prince William Sound Risk Assessment

This reference is not to the actual document titled *The Prince William Sound Risk Assessment*, but rather to the review of that study, called *Review of the Prince William Sound, Alaska, Risk Assessment Study*, that was performed by a National Research Council (NRC) committee. It evaluated the methods used in the Prince William Sound (PWS) Risk Assessment and their appropriateness for supporting the study's conclusions and recommendations. The NRC review of the PWS Risk Assessment highlights several concerns with the study and its conclusions. The report summarizes its findings in three areas: 1) models used to assess risk, 2) data collection and use, and 3) report conclusions and recommendations.

The authors indicated in the review document that the study findings and recommendations are not necessarily applicable to other areas. However, lessons from the review can assist in the implementation of this project. Observations regarding justification of assumptions, data collection methods, and modeling transparency are particularly relevant to the project.

3.4.2.3 Aleutian Islands Risk Assessment Design

This reference provides an overall plan for performing a risk assessment expected to be sponsored by the State of Alaska and the U.S. Coast Guard in the next 1-2 years. It suggests a two-step risk assessment approach which will, 1) qualitatively or semi-quantitatively identify those events that are high risk, and 2) quantitatively analyze only the high risk events and risk mitigation options for the purpose of identifying appropriate recommendations. This two-step approach helped to influence the methodology selected for this project. The approach for this project differs somewhat from that which was recommended for the Aleutian Islands study, due largely to the differences in the scope and objectives for the two studies. However, the report provides useful comments relating to portrayal of risk assessment results. These were considered in the ARA Project approach for risk summarization (see Section 9 of this report).

3.4.2.4 Business Continuity or Availability Assessments by Infrastructure Operators

These studies have objectives that are similar to the reliability focus of this project. Based on discussions with state agency representatives, such studies are generally a requirement for initial approval of new infrastructure or development projects, but they are not necessarily required to be submitted to the State on an ongoing basis. Therefore, the studies that state agencies have available in their files are likely to be outdated. People familiar with industry practice have indicated that a wide range of policies exist among the infrastructure operators regarding the level of sophistication in business continuity and availability studies. Some operators have apparently prepared such studies on a periodic basis and use them as an important part of managing their business. Other operators, generally those who have not experienced unexpected downtime problems, have not been as proactive in performing such studies. Although such studies focus on the reliability of the throughput for company revenues rather than state revenues, the two goals are complementary for purposes of this risk assessment. Business continuity studies prepared by operators are not currently available but would be valuable to the project for the reliability assessment portion of the implementation phase.

3.4.2.5 Integrity Management Risk Assessments under DOT Regulatory Requirements

Integrity management risk assessments performed under the DOT pipeline regulations[4,5] address many of the reliability assessment issues of concern to this project. These regulations apply to the oil and gas pipelines regulated by DOT in Alaska. The integrity management plans prepared by operators are available to the state through the Joint Pipeline Office (JPO) and DOT. However, based on the current understanding of the disposition of those submittals, it is not clear whether the details of the risk assessments required by those studies are ever submitted to the agencies. The agencies have only the integrity management plans (i.e., how the operators will perform integrity management to meet the regulations) and the results of their integrity management efforts (i.e., what the operators found and fixed in their integrity efforts). The risk assessment performed as part of the actual performance of the work is not generally submitted and much of the information this project will need to facilitate the reliability risk assessment belongs in that category.

Studies have been performed and/or updated recently for the facilities in which the integrity management regulations applied since they were initially developed. However, some new pipelines have more recently become covered under the integrity management regulations. It is not clear what the current status of integrity management risk assessments is for all of the oil and gas infrastructure facilities at this time.

3.4.2.6 OSHA Process Safety Management and EPA Risk Management Hazard Analyses

The required OSHA and EPA process hazard studies should address most of the State's safety concerns within the scope of this project. However, not all oil and gas production facilities are subject to these regulations. Some of the operators perform similar studies even when the specific regulations do not apply to their facilities, but the fraction of the facilities within the scope of this project that have such studies on file is currently not documented.

Studies required by these particular regulations have to be updated every five years, so the studies are likely to be relatively current, if available. Regulations also require that impacts to the studies must be considered by operators when major changes are made to processes that are covered by the studies.

3.5 Stakeholder Input

The purpose of the stakeholder consultation process was to identify, engage, and collect input from key stakeholders that have an interest in the outcome of the project. Stakeholders included oil and gas infrastructure owners/operators, state and federal agencies, the University of Alaska, local governments, NGOs, native organizations, and the general public. The stakeholder consultation effort was designed to seek input from key stakeholders on concerns for possible consideration in the overall evaluation of the risks associated with the continued operations of the oil and gas infrastructure in Alaska.

Consultation with key stakeholders was conducted from June through November 2008 as part of the planning phase of the project (Task 1b Stakeholder Consultation). During this time, direct contact was made with over 200 interested parties, 39 meetings were held around the state, and written comments were solicited from stakeholders. In addition to stakeholder meetings that were held to obtain input, stakeholders were given many other avenues and options to provide feedback and communicate their concerns and perspectives. Key stakeholder input for use in the development of the proposed methodology was accepted through the cutoff date of November 4, 2008. Input received after the cutoff date was forwarded to the State Agency Oversight Team (SAOT) for consideration.

The stakeholder consultation process was designed to gather general, as well as focused input, on priorities and concerns regarding the oil and gas infrastructure. Stakeholders were asked to address the following specific topics that are relevant to the development of the proposed methodology:

- **Focus of the Risk Assessment:** Stakeholders were asked for input on the portions of existing oil and gas industry infrastructure they felt warranted the project team's attention.
- **Initiating Events:** Stakeholders were asked for input on events that have the potential to cause catastrophes relating to the infrastructure.
- **Consequences of Concern:** Within the categories of impact to human safety, impact to the environment, or production/revenue loss, stakeholders were asked to provide input on what kinds of events they would consider to be the most significant.
- **Other Specific Priorities and Concerns:** Stakeholders were encouraged to provide input to the project team on other specific priorities and concerns that should be considered as part of the risk assessment.
- **Existing Risk Assessments, Studies, Reports, or Other Data/Information Relevant to Alaska Oil and Gas Infrastructure:** Stakeholders were asked to provide recommendations for existing data and information relating to the Alaska oil and gas Infrastructure which could be reviewed and applied to the development of a fit for purpose risk assessment methodology to address the risks associated with the infrastructure.

Common themes of input were generated from a state-wide perspective, as well as specific themes as they relate to the three main regions of the oil and gas infrastructure in Alaska: North Slope, TAPS, and Cook Inlet. The approved key stakeholder list, record of stakeholder contacts, and comprehensive meeting records were documented in the Interim Report that was issued in January 2009.

Stakeholder input included the following systematic recommendations for consideration in the proposed methodology:

- Consideration of OSHA Process Safety Management (PSM) risk management concepts.

- Consideration of common cause failures (e.g., an earthquake that causes damage to multiple facilities), criticalities in the system (i.e., looking at key pieces of a system to identify critical elements and points of failure), and systematic interdependencies.

- Consideration of direct, indirect, and cumulative consequences.

Stakeholder input has been incorporated into the proposed methodology in order to augment general risk assessment best systematic practices and to align the methodology with the general stakeholder themes that are common across the scope of the oil and gas production infrastructure in Alaska. Stakeholder input was primarily applicable in refining the components of initiating events and significant consequences in the proposed methodology. Additionally, stakeholder input provided data source recommendations that have been used to customize the proposed operational hazards and natural hazards assessments. The proposed methodology overview is included in Section 2.2.

3.5.1 Initiating Events

This component of risk assessment methodology describes a listing of events that answer the first question of a risk assessment; "What can go wrong?" An initiating event is the first incident that causes or contributes to a deviation from the normal design or operational intent of a system. This list is intended to be a preliminary set of event categories which would be specifically applicable to Alaska infrastructure. The concept of initiating events assumes that there is a normal mode of acceptable operation based on original and approved design standards, configuration, and approved permits.

Much of the stakeholder input was focused on the events that might occur with aging components of the Alaska oil and gas infrastructure and problems with operation of existing infrastructure, and therefore a concern to the individuals and organizations that provided the input. Stakeholders identified events that involved deviation of normal operations under various scenarios which generally fit into the broad categories of operational hazards and natural hazards.

The results of the stakeholder input were considered with other available information to derive a preliminary listing of event categories that will be considered during implementation of the risk assessment as described in Sections 7 and 8. This list has been expanded and refined during the methodology development process and allows for the development of a customized, structured set of scenarios that take into account the design and operating features that are specific to the infrastructure facility or component being considered.

The hazardous scenarios that will be postulated during risk assessment implementation are those events that are unplanned and undesired, and have the potential to cause impacts to safety, the environment, or reliability of the producing infrastructure. The initiating events to be considered have been divided into two categories: 1) operational hazard events, which are related to the operating processes that make up the infrastructure system, and 2) natural hazard events, which are caused by naturally occurring phenomenon in the environment.

Initiating event input was received from stakeholders and general risk assessment practices. The proposed methodology includes general scenarios and considers the design and operating features that are specific to the infrastructure components within the scope of the project. Initiating events identified by stakeholders include the following:

- Failure of aging infrastructure
- Failure of abandoned infrastructure

- Failure of vertical pipeline supports
- Loss of power
- Corrosion
- Changes in process conditions
- Changes in industry workforce
- Natural hazards

3.5.2 Operational Hazard Events

Operational hazard events are those events that relate specifically to the processes, systems, and equipment that make up the oil and gas infrastructure and can be caused by human actions or equipment or system malfunctions associated with the operations of a system. These events can occur within the boundaries of a plant or facility and are a result of oil and gas system operations activities and tasks and are included in Section 7.1.

The following is a general list of the types of operational hazards and contributing factors that were identified through stakeholder consultation and other input sources for Alaska oil and gas infrastructure:

- Fire
- Explosion
- Loss of integrity (spills and leaks) due to natural aging process (e.g., corrosion, abrasion, wear and fatigue)
- Equipment malfunction
- Loss of infrastructure support systems (e.g., power)
- Changes in process conditions (e.g., composition– heavy oil, increased quantities of sand, throughput decline, increased gas oil ratio, water influx, H_2S generation, etc.)
- Severe weather conditions (e.g., cold temperatures that contribute to safety system failures)
- Human error (e.g., fatigue, failure to follow proper procedures, resource availability, etc.)

3.5.3 Natural Hazard Events

Natural hazards are naturally occurring phenomenon external to the oil and gas infrastructure and are outside of operations. Natural hazards include atmospheric, hydrologic, geologic (especially seismic and volcanic), and wildfire phenomena that, because of their location of occurrence, severity, and frequency, have the potential to affect the oil and gas infrastructure adversely. Natural hazard methodology categories are included in Section 8.1.

The following is a general list of natural hazards identified through stakeholder consultation and other input sources for Alaska oil and gas infrastructure, and served as a consideration in selecting the proposed methodology:

- Earthquakes
- Tsunamis
- Volcanoes (including ash, lahars, etc.)
- Coastal erosion

- Permafrost thaw/climate change
- Ice
- Severe storms
- Flooding
- Underwater currents
- High winds
- Geology (e.g. subsidence, landslides)
- Avalanches
- Forest Fire

3.5.4 Significant Consequences

Risk assessment methodologies evaluate "What is the expected frequency/likelihood of an event occurring?" and "What are the consequences if that event occurs?" The risk of such events can be expressed as the combination of the magnitude of the consequences associated with the event and the frequency with which such an event is expected to occur. Overall risks can be managed by minimizing or mitigating risk levels, which can be accomplished by either reducing the magnitude of the consequences of the event (assuming that the event has occurred) or by reducing the likelihood (expected frequency) that the event could occur.

The proposed methodology utilizes a "significant consequence" approach focused on the three major classes of consequences defined by the State. It should be noted that this was originally referred to as "unacceptable consequences." However, to be as accurate as possible in terms of risk assessment language, the term "significant" has been selected for use throughout this document. A wide range of stakeholder input was considered in developing the consequence component of the proposed methodology. Methodology definitions are based on both stakeholder input and best available risk assessment practices and tools. The proposed methodology identifies consequences of interest for the risk assessment as impacts of potential events that pose threats to:

- Safety (Occupational and Public)
- Environment
- Reliability of state revenue due to loss of production

These three consequence classes were defined, categorized, and analyzed, and stakeholder input was considered relative to the proposed methodology in Sections 7 and 8. In providing input on "significant" consequences, stakeholders generally indicated that some components of oil and gas infrastructure represented higher levels of risk than others. The proposed methodology accounts for this distinction by providing a preliminary screening of components where significant outcomes would not be experienced under worst case scenarios. This preliminary screening approach is described in Section 6.

Stakeholder input on significant consequences has been incorporated into the proposed methodology for specific consequence classifications. Detailed operational and natural hazard methodologies are included as Sections 7 and 8 of this report.

3.5.5 Safety Consequences

Safety impacts include both occupational health and safety (i.e., impacts to personnel that work in and on oil and gas infrastructure facilities and equipment) and public health and safety (impacts to members of the public at large who reside near or are located within the local boundaries of the operating infrastructure equipment and facilities). Stakeholder input included a general concern for any occupational and public health and safety consequence, regardless of the source of the hazard.

The health and safety consequences that are considered in the proposed methodology include only those impacts that result from events involving operational failures of the oil and gas infrastructure equipment, including failures caused by equipment defects, degradation, improper operation, or inadequate maintenance and natural hazard events. Transportation accidents, falls, construction activities, and confined space accidents are a common concern of stakeholders but are unrelated to infrastructure equipment operations and will not be included in the methodology. Health consequences from the normal operation of infrastructure as designed, configured, and permitted are not included in the scope of the risk assessment.

Based on stakeholder input that any safety impact is significant, the safety consequence component of the proposed methodology considers any person that could potentially be located within the vicinity of the impact of a significant operational event would be potentially exposed to life threatening or fatal injuries. The proposed methodology will assign a consequence category to an event based on the higher of occupational or public safety impact.

3.5.6 Environmental Consequences

A major aspect of stakeholder input received during the consultation process concerned issues regarding potential environmental impacts of oil and gas infrastructure failures which lead to a loss of containment and release to the environment. While clearly a stakeholder concern, the proposed methodology does not consider environmental impacts that are potentially a result of normal operations based on original and approved design standards, configuration, and permitting. For example, permitted activities such as flaring or permitted discharge of treated produced water to the Cook Inlet are excluded because they are legal activities. The proposed methodology considers events to be significant if they:

- Affect specific valued species, resources, and/or habitat
- Involve a wide-spread area
- Have long term or persistent effects
- Restrict access to areas due to pollution effects

The proposed methodology defines how each of the environmental factors will be considered and applied from a consequence standpoint. The factors that are contributors to the severity of an event which causes an environmental impact include:

- *Local Environmental Sensitivity*– Stakeholder input indicated the actual location characteristics (geography/topography of the area, e.g. land area or waterway) and the types of animal and plant species and activities which are dependent on the affected area are important.

- *Type and Amount of Material Spilled* - Stakeholder input indicated environmental impacts varied depending on the nature of the released material (crude oil, produced water, gas, seawater, etc.).

- *Release Recoverability/Remediation* - Stakeholder input indicated that the ability of the infrastructure operator to detect and respond to the spill, the climate conditions under which the release event occurs, and the resultant ability for mitigation and remedial activities to occur has a direct bearing on environmental impact and duration of the impacts. The proposed methodology accounts for both the characteristics and climate of the release location and the capability of the response organization to perform the required remedial activities.

Due to the unique nature of both the Alaska environment and specific stakeholder input, a definition of areas of high environmental consequence has been customized for the environmental consequence categories described in the proposed methodology. Stakeholder input and other available public sources of information were used to develop and refine the definition.

Stakeholders specifically highlighted the issues of subsistence, traditional lifestyle activities, areas of cultural significance; wildlife and human habitat which support tourism and recreational activities, and other key issues unique to the three regions of oil and gas infrastructure in Alaska. These consequences were added to the definition of environment impact categories of significance in the proposed methodology.

3.5.7 Reliability Consequences

Reliability was defined by the State for this project and means the continuity of production of oil and gas from which the state government receives its revenue. In this risk assessment, disruption of a production stream that is severe enough to have a significant impact on state revenue is considered to be a reliability consequence. While stakeholder input was widely received for safety and environmental consequences, input on reliability in terms of the State's definition was from a relatively narrow number of sources.

Stakeholders raised numerous economic consequence issues that do not fall within the scope of this project as defined by the State. These additional economic losses (and potential for associated safety impacts) are clearly issues of significant consequence and concern to the stakeholders. However, those impacts relate to secondary, socioeconomic consequences that were not defined as consequence areas of concern and are outside the scope of this project. The focus of this project is restricted only to direct state revenue losses. As a result, the risk assessment team is recommending socioeconomic risks as an area for future study.

The proposed methodology for assessing the consequence levels related to reliability is primarily driven by stakeholder input received from the State Department of Revenue. The proposed methodology will assess the potential impact to state revenue from unplanned events that interrupt or reduce oil and gas production flow, and therefore result in loss of revenue from royalties and taxes. Specific thresholds of oil and gas production and revenue impact were identified by the state Department of Revenue and were incorporated into the proposed methodology.

3.5.8 Information Sources and Data Recommendations

Stakeholders submitted various forms of recommended technical and non-technical references, information sources, and individual documents in response to requests for input during the stakeholder consultation process. Approximately 102 individual information and data source submittals were made during the process through both verbal and written means. In some cases, stakeholders identified general organizational information or general data sources. In other cases, stakeholders identified specific personnel to consult or specific documentation or information references.

The input on information sources and recommended data were accumulated in a standardized fashion and were utilized as appropriate in developing the proposed methodology. The majority of information sources and data recommendations pertained to data requirements for execution of the risk assessment and will be referenced during the implementation phase of the risk assessment. Some information and recommended data sources identified by stakeholders are not considered to be within the scope of this risk assessment and will not be used.

4 PHYSICAL INFRASTRUCTURE SCOPE

The purpose of this section is to present the detailed scope of the physical infrastructure for the project. The information included in this section is summarized from a master data record that was developed to capture and organize the infrastructure facilities and associated components within the scope of the project. This data record continues to be refined as information is gathered from publicly available sources, and will be the basis of the nodal breakdown described in Section 5 of this report. Much of this data, including data on specific wells, has been sourced from the Alaska Oil and Gas Conservation Commission's (AOGCC) Online Public Databases.[6]

Note: Production and wells data which has been extracted and summarized here will be used as the basis for the production data throughout the rest of this study (through implementation – Phase 2).

The detailed physical scope of each of the following three separate infrastructure regions is described in Sections 4.1 through 4.3:

- North Slope
- Cook Inlet
- Trans Alaska Pipeline System (TAPS)

Each section contains a brief overview of the facilities and associated components included in the scope for the particular infrastructure region, as well as excluded facilities and components and the reasons for their exclusion. Areas of future oil and gas development (i.e., production start-up after July 1, 2008) are excluded from the scope of the project.

The North Slope and Cook Inlet sections are each represented as two physical infrastructure scope tables. The first includes the facilities in the region and their associated drillsites/wellpads and pipelines, and the second contains the pipelines of each region. The term "pipeline" as used throughout this proposed methodology includes both common carrier pipelines and non-common carrier pipelines. (Refer to Section 5.1 for project specific definitions of pipelines and other equipment.)

The TAPS section contains only one table, which breaks down each major TAPS component:

- Pump stations
- Pipeline segments of the TAPS and the fuel gas line
- The Valdez Marine Terminal (VMT).

Detailed maps of the North Slope, Cook Inlet, and TAPS infrastructure areas are included as Appendix A to this report.

4.1 North Slope

The project scope for the North Slope infrastructure includes production facilities and pipelines that deliver oil to Pump Station 1 in Prudhoe Bay. In general, the project scope begins at the wellbore of the production or service well and does not include issues associated with reservoirs, formations, and associated down-hole production. Additionally, the scope ends at the point of delivery, and generally does not include distribution systems.

The major North Slope infrastructure Operating Areas/Units included in the scope of this project are listed below with their respective fields, and are shown visually in Figure 4-1 and Figure 4-2. In addition, common carrier pipelines within the region have been identified.

- Kuparuk River Unit – includes the Kuparuk field and satellites West Sak, Tabasco, Tarn and Meltwater
- Colville River Unit – includes the Alpine (CD1 and CD2) field and satellites Fiord (CD3) and Nanuk (CD4)
- Milne Point Unit
- Ooguruk Unit
- Prudhoe Bay Unit
  - Greater Prudhoe Bay (GPB) – includes the Prudhoe Bay Initial Participating Area (IPA) and satellites Aurora, Borealis, Midnight Sun, Orion, and Polaris
  - Greater Point McIntyre Area (GPMA) – includes the Point McIntyre field and satellites Lisburne, Niakuk / Raven, West Beach/North Prudhoe Bay
- Duck Island Unit/Endicott – includes Endicott (Main Production Island, or MPI), and satellites Eider and Sag Delta North (Satellite Drilling Island, or SDI)
- Northstar Unit
- Badami Unit
- Associated Pipelines

Out of scope components include the following:

- Units and Associated Pipelines to Facilities – Units in exploration or not currently producing as of July 1, 2008, including Liberty, Point Thomson, Nikaitchuq, and Alpine satellites Qannik (extended reach drilling from CD2), Alpine West (CD5), Lookout (CD6) and Spark (CD7).
- Nuiqsut Natural Gas Pipeline and Associated Receiving Facilities – This is a distribution pipeline that provides natural gas to the village of Nuiqsut.
- Barrow Gas Fields and Associated Pipeline Distribution System – These fields provide natural gas distribution and sales to the City of Barrow for the generation of electric power and residential heating only. The facilities are not tied to the overall North Slope oil and gas production infrastructure. They are separate from the primary North Slope Infrastructure region.

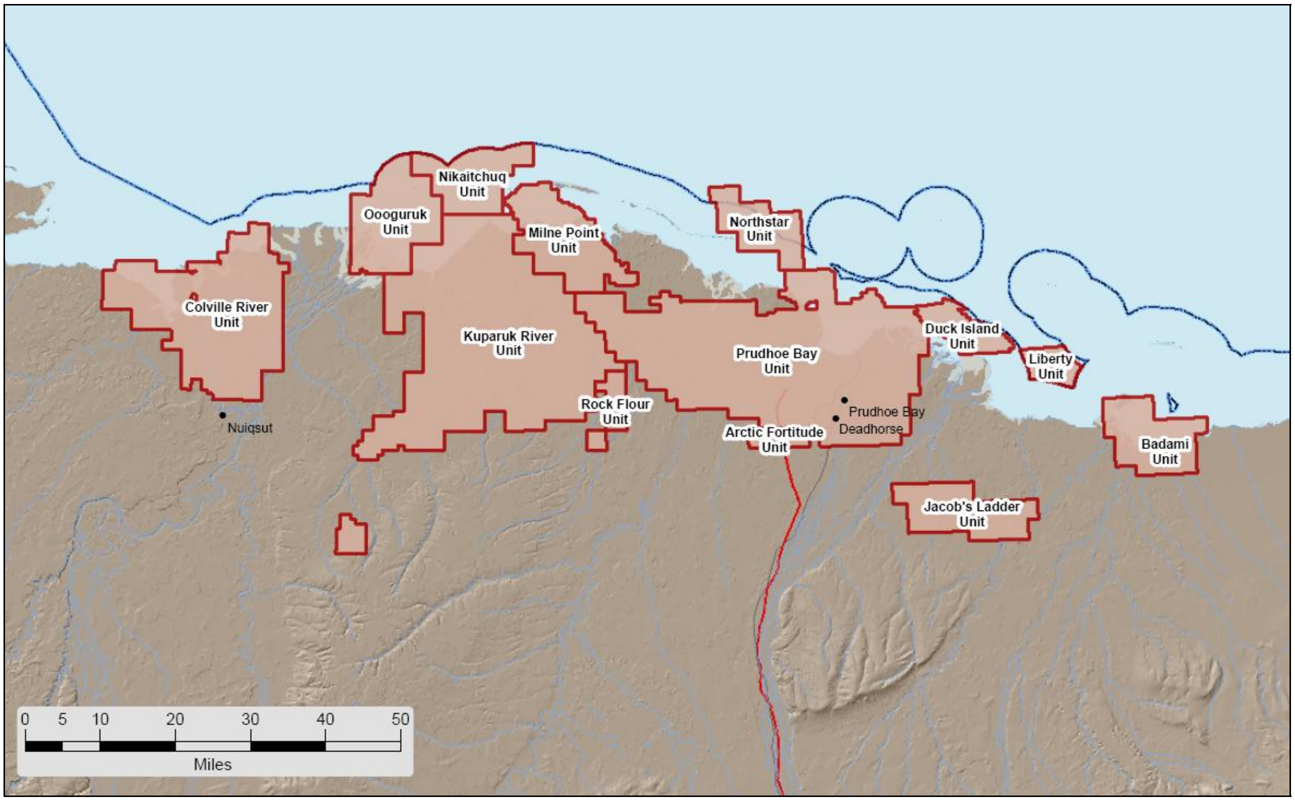

Figure 4-1 Oil and Gas Units of the North Slope of Alaska[7]

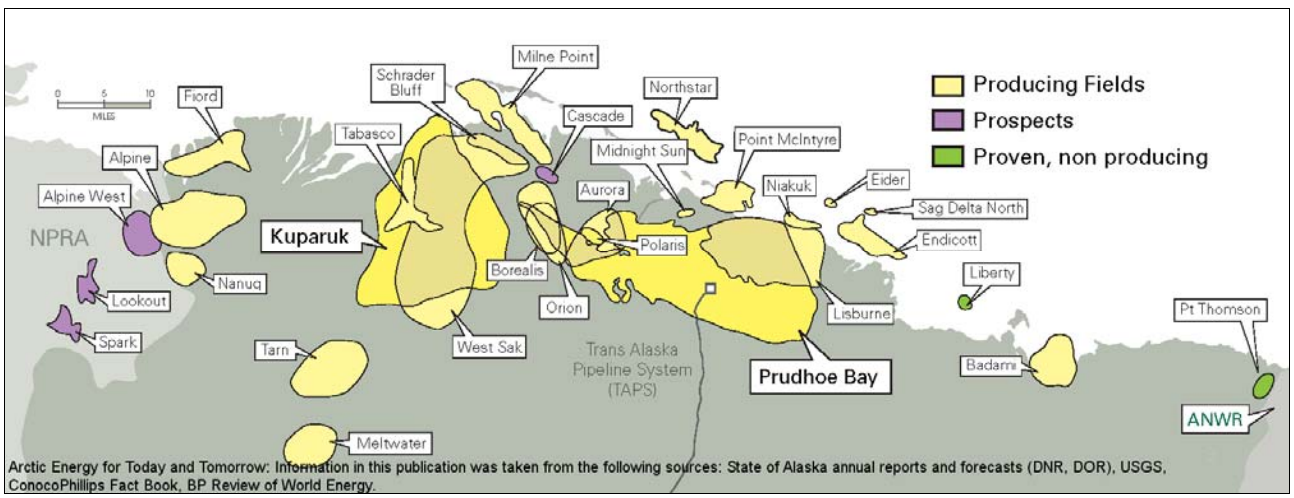

Figure 4-2 North Slope Oil Fields[8]

The following table (Table 4-1), outlines the detailed scope of North Slope facilities and their associated components based on a review of publicly available data. North Slope Pipelines are shown in Table 4-2.

Table 4-1 Physical Scope of North Slope Infrastructure[6]

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
Kuparuk River Unit									
KRU CPF1 (Kuparuk Central Processing Facility 1)	1A Pad	14	-	-	13	-	-	27	KRU 1A to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1A
	1B Pad	19	2	-	9	-	5	35	KRU 1B to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1B
	1C Pad WSAK	38	12	-	14	-	-	64	KRU 1C to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1C
	1D Pad WSAK	48	23	-	11	-	-	82	KRU 1D to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1D
	1E Pad	34	25	-	9	-	-	68	KRU 1E to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1E
	1F Pad	13	-	-	9	-	-	22	KRU 1F to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1F
	1G Pad	8	-	-	9	-	-	17	KRU 1G to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1G
	1H Pad	12	8	-	2	-	-	22	KRU 1H to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1H
	1J Pad	46	38	-	-	-	-	84	KRU 1J to KRU 1D Production Pipeline Water Injection Pipeline to KRU 1J
	1L Pad	22	3	-	8	-	-	33	KRU 1L to KRU 1F Production Pipeline Gas and Water Injection Pipelines to KRU 1L
	1M Pad	1	-	-	-	-	-	1	KRU 1M to CPF1 Production Pipeline

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
KRU CPF1 (cont.)	1Q Pad	6	-	-	11	-	-	17	KRU 1Q to KRU 1Y Production Pipeline Gas and Water Injection Pipelines to KRU 1Q
	1R Pad	19	-	-	14	1	-	34	KRU 1R to KRU 1G Production Pipeline Gas and Water Injection Pipelines to KRU 1R
	1Y Pad	19	-	-	14	-	-	33	KRU 1Y to CPF1 Production Pipeline Gas and Water Injection Pipelines to KRU 1Y
	CPF-01A	-	-	-	-	1	-	1	
KRU CPF2 (Kuparuk Central Processing Facility 2)	2A Pad	15	-	-	10	-	-	25	KRU 2A to KRU 2B Production Pipeline Gas and Water Injection Pipelines to KRU 2A
	2B Pad	8	-	-	8	-	-	16	KRU 2B to CPF2 Production Pipeline Gas and Water Injection Pipelines to KRU 2B
	2C Pad	8	-	-	8	-	-	16	KRU 2C to CPF2 Production Pipeline Gas and Water Injection Pipelines to KRU 2C
	2D pad	9	-	-	8	-	-	17	KRU 2D to KRU 2C Production Pipeline Gas and Water Injection Pipelines to KRU 2D
	2E Pad	7	3	-	-	-	-	10	KRU 2E to KRU 2D Production Pipeline Water Injection Pipeline to KRU 2E
	2F Pad	12	1	-	8	-	-	21	KRU 2F to CPF2 Production Pipeline Gas and Water Injection Pipelines to KRU 2F
	2G Pad	9	-	-	8	-	-	17	KRU 2G to CPF2 Production Pipeline Gas and Water Injection Pipelines to KRU 2G
	2H Pad	9	-	-	8	-	-	17	KRU 2H to KRU 2B Production Pipeline Gas and Water Injection Pipelines to KRU 2H

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
KRU CPF2 (cont.)	2K Pad	16	-	-	12	-	-	28	KRU 2K to KRU 2H Production Pipeline Gas and Water Injection Pipelines to KRU 2K
	2L Pad Tarn	10	-	-	4	-	-	14	Tarn Meltwater Production Pipeline from KRU 2L to KRU 2M Gas and Water Injection Pipelines to KRU 2L
	2M Pad	17	-	-	17	1	-	35	KRU 2M to KRU 2B Production Pipeline Gas and Water Injection Pipelines to KRU 2M
	2N Pad Tarn	25	-	-	13	-	-	38	Tarn Meltwater Production Pipeline from KRU 2N to KRU 2L Gas and Water Injection Pipelines to KRU 2N
	2P Pad Melt	12	-	-	7	-	-	19	Tarn Meltwater Production Pipeline from KRU 2P to KRU 2N Gas and Water Injection Pipelines to KRU 2P
	2T Pad Tabasco	29	-	-	14	-	-	43	KRU 2T to KRU 2A Production Pipeline Gas and Water Injection Pipelines to KRU 2T
	2U Pad	9	-	-	7	-	-	16	KRU 2U to KRU 2V Production Pipeline Gas and Water Injection Pipelines to KRU 2U
	2V Pad	8	-	-	8	-	-	16	KRU 2V to CPF2 Production Pipeline Gas and Water Injection Pipelines to KRU 2V
	2W Pad	9	-	-	8	-	-	17	KRU 2W to KRU 2V Production Pipeline Gas and Water Injection Pipelines to KRU 2W

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
KRU CPF2 (cont.)	2X Pad	10	-	-	8	-	-	18	KRU 2X to CPF2 Production Pipeline to Kuparuk Extension Gas and Water Injection Pipelines to KRU 2Z
	2Z Pad	13	1	-	11	-	-	25	KRU 2Z to CPF2 Production Pipeline to Kuparuk Extension Gas and Water Injection Pipelines to KRU 2Z
	CPF-02	-	-	-	-	1	-	1	
KRU CPF3 (Kuparuk Central Processing Facility 3)	3A Pad	10	8	-	-	-	-	18	KRU 3A to CPF3 Production Pipeline Water Injection Pipeline to KRU 3A
	3B Pad	8	-	-	8	-	-	16	KRU 3B to CPF3 Production Pipeline Gas and Water Injection Pipelines to KRU 3B
	3C Pad	11	5	-	-	-	-	16	KRU 3C to CPF3 Production Pipeline Water Injection Pipeline to KRU 3C
	3F Pad	11	-	-	12	-	-	23	KRU 3F to KRU 3B Production Pipeline Gas and Water Injection Pipelines to KRU 3F
	3G Pad	17	2	-	6	-	-	25	KRU 3G to KRU 3F Production Pipeline Gas and Water Injection Pipelines to KRU 3G
	3H Pad	20	3	-	8	-	-	31	KRU 3H to KRU 3A Production Pipeline Gas and Water Injection Pipelines to KRU 3H
	3I Pad	8	9	-	-	-	-	17	KRU 3I to CPF3 Production Pipeline Water Injection Pipeline to KRU 3I
	3J Pad	10	9	-	-	-	-	19	KRU 3J to CPF3 Production Pipeline Water Injection Pipeline to KRU 3J

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
KRU CPF3 (cont.)	3K Pad	17	15	-	1	-	-	33	Oliktok Pipeline from KRU 3K to CPF3 Gas and Water Injection Pipelines to KRU 3K
	3M Pad	17	12	-	-	-	-	29	KRU 3M to KRU 3I Production Pipeline Water Injection Pipeline to KRU 3M
	3N Pad	12	8	-	2	-	-	22	Oliktok Pipeline from KRU 3N to CPF3 Gas and Water Injection Pipelines to KRU 3N
	3O Pad	14	1	-	8	-	-	23	Oliktok Pipeline from KRU 3O to CPF3 Gas and Water Injection Pipelines to KRU 3O
	3Q Pad	9	-	-	9	-	-	18	Oliktok Pipeline from KRU 3Q to CPF3 Gas and Water Injection Pipelines to KRU 3Q
	3R Pad	7	5	-	-	1	-	13	Oliktok Pipeline from KRU 3R to CPF 3 Water Injection Pipeline to KRU 3R
	3S Pad	9	-	-	8	-	-	17	KRU 3S to KRU 3G Oil Pipeline
Kuparuk Support Facilities (Kuparuk Seawater Treatment Plant Kuparuk Topping Unit)	N/A								
Waste Disposal/Service Wells	KRU WS2	-	-	-	-	10	1	11	
Milne Point Unit									
Milne Point Central (MPC)	MPU A	-	-	-	-	-	-	-	MPU A to MPC Production Pipeline Production Pipeline from MPU C

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
MPC (cont.)	MPU B	14	10	-	-	1	-	25	MPU B to MPC Production Pipeline Production Pipeline from MPU D Water Injection Pipeline to MPU B
	MPU C	19	2	-	11	-	-	32	MPU C to MPU A Production Pipeline Production Pipeline from MPU L Gas and Water Injection Pipelines to MPU C
	MPU D	2	-	-	-	-	-	2	MPU D to MPU B Production Pipeline
	MPU E	23	2	1	9	-	-	35	MPU E to MPC Production Pipeline Production Pipeline from MPU K Gas and Water Injection Pipelines to MPU E
	MPU F	31	2	-	21	-	-	54	MPU F to MPU L Production Pipeline Gas and Water Injection Pipelines to MPU F
	MPU G	12	9	-	-	-	-	21	MPU G to MPC Production Pipeline Production Pipeline from MPU H Water Injection Pipeline to MPU G
	MPU H	19	5	-	-	-	-	24	MPU H to MPU G Production Pipeline Production Pipeline from MPU_I Production Pipeline from MPU_J Water Injection Pipeline to MPU H
	MPU I	20	6	-	-	-	-	26	MPU I to MPU H Production Pipeline Water Injection Pipeline to MPU I
	MPU J	21	8	-	-	-	-	29	MPU J to MPU H Production Pipeline Water Injection Pipeline to MPU J

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
MPC (cont.)	MPU K	10	4	-	-	-	-	14	MPU K to MPU E Production Pipeline Water Injection Pipeline to MPU K
	MPU L	21	-	-	-	-	-	21	MPU L to MPU C Production Pipeline Production Pipeline from MPU_F
	MPU S	31	17	-	-	-	-	48	MPU S to MPC Production Pipeline Water Injection Pipeline to MPU S
Colville River Unit									
Alpine Central Facility (ACF)	CD-1	23	1	1	20	2	-	47	Alpine CD1 to Alpine ACF Production Pipeline Gas and Water Injection Pipelines to Alpine CD1
	CD-2	37	7	-	6	-	-	50	Alpine CD2 to Alpine CD1 Production Pipeline Gas and Water Injection Pipelines to Alpine CD2
	CD-3	9	-	-	6	-	-	15	Alpine CD3 to Alpine ACF Production Pipeline Gas and Water Injection Pipelines to Alpine CD3
	CD-4	11	2	-	6	-	-	19	Alpine CD4 to Alpine ACF Production Pipeline Alpine ACF to Alpine CD4 Water Injection Pipeline

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
Oooguruk Unit									
Oooguruk Tie-In Pad (OTP)[9]	Oooguruk	2	-	-	-	1	-	3	Drillsite to OTP Subsea Production Pipeline OTP to Drillsite Subsea Water Injection, Gas Injection/Artificial Lift (Gas Lift) and Diesel/Mineral Oil Pipelines OTP to DS3H Multiphase Pipeline Kuparuk DS3A to OTP Water Injection Pipeline
Prudhoe Bay Unit									
FS-1	DS1	29	3	-	-	-	-	32	PBU DS1 to FS1 Production Pipeline Water Injection Pipeline to DS1
	DS12	25	-	-	11	-	-	36	PBU DS12 to PBU DS1 Production Pipeline Gas and Water Injection Pipelines to DS12
	DS18	42	-	-	-	-	-	42	PBU DS18 to FS1 Production Pipeline
	DS2	43	-	-	-	-	-	43	PBU DS2 to FS1 Production Pipeline
	DS5	39	-	-	-	-	-	39	PBU DS5 to FS1 Production Pipeline
FS-2	DS11	26	5	-	3	-	-	34	PBU DS11 to FS2 Production Pipeline Gas and Water Injection Pipelines to DS11
	DS16	23	1	-	7	-	-	31	PBU DS16 TO PBU DS3 Production Pipeline Gas and Water Injection Pipelines to DS16
	DS17	15	-	-	5	-	-	20	PBU DS17 TO PBU DS3 Production Pipeline Gas and Water Injection Pipelines to DS17

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
FS-2 (cont.)	DS3	25	-	-	12	-	-	37	Production Pipeline from PBU DS16 Production Pipeline from PBU DS17 PBU DS3 to FS2 Production Pipeline Gas and Water Injection Pipelines to DS3
	DS4	30	15	-	4	-	-	49	PBU DS4 to FS2 Production Pipeline Gas and Water Injection Pipelines to DS4
	DS9	31	7	-	13	-	-	51	PBU DS9 to FS2 Production Pipeline Gas and Water Injection Pipelines to DS9
FS-3	DS13	20	-	-	17	-	-	37	PBU DS13 to PBU DS6 Production Pipeline Gas and Water Injection Pipelines to DS13
	DS14	35	-	-	9	-	-	44	PBU DS14 to FS3 Production Pipeline Gas and Water Injection Pipelines to DS14
	DS15	51	-	-	-	-	-	51	PBU DS15 to PBU DS7 Production Pipeline
	DS6	24	-	-	-	-	-	24	Production Pipeline from PBU_DS13 PBU DS6 to FS3 Production Pipeline
	DS7	36	-	-	-	-	-	36	PBU DS7 to FS3 Production Pipeline
GC-1	D Pad	32	-	-	-	-	-	32	PBU D to GC1 Production Pipeline
	E Pad	40	3	-	-	-	-	43	PBU E to GC1 Production Pipeline Water Injection Pipeline to PBU E
	F Pad	46	1	-	-	-	-	47	PBU F to GC1 Production Pipeline Water Injection Pipeline to PBU F
	G Pad	28	-	-	-	-	-	28	PBU G to GC1 Production Pipeline

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
GC-1 (cont.)	K Pad Lisb	20	-	-	-	-	-	20	PBU K to GC1 Production Pipeline
GC-2	H Pad	33	-	-	2	1	-	36	Production Pipeline from PBU_Y PBU H to GC2 Production Pipeline Gas and Water Injection Pipelines to PBU H
	J Pad	28	-	-	-	-	-	28	Production Pipeline from PBU R PBU J to GC2 Production Pipeline
	L Pad SB/Bore/Orion	44	7	-	13	-	-	64	PBU L to GC2 Production Pipeline Gas and Water Injection Pipelines to PBU L
	M Pad Polaris	24	-	-	9	-	-	33	Production Pipeline from PBU S PBU M to PBU N Production Pipeline Gas and Water Injection Pipelines to PBU M
	N Pad	23	1	-	6	-	-	30	Production Pipeline from PBU M PBU N to GC2 Production Pipeline Gas and Water Injection Pipelines to PBU N
	P Pad	24	2	-	6	-	-	32	PBU P to PBU Y Production Pipeline Gas and Water Injection Pipelines to PBU P
	Q Pad	8	-	-	-	-	-	8	PBU Q to GC2 Production Pipeline
	R Pad	23	2	-	11	-	-	36	PBU R to PBU J Production Pipeline Gas and Water Injection Pipelines to PBU R
	S Pad Auro/Polaris	56	4	-	23	-	-	83	PBU S to PBU M Production Pipeline Gas and Water Injection Pipelines to PBU S

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
GC-2 (cont.)	U Pad	10	4	-	-	-	-	14	Production Pipeline from PBU W Production Pipeline from PBU Z PBU U to GC2 Production Pipeline Water Injection Pipeline to PBU U
	V Pad Bore/Pol/SB	39	2	-	19	-	-	60	PBU V to GC2 Production Pipeline Gas and Water Injection Pipelines to PBU V
	W Pad Polaris	42	6	-	11	1	-	60	PBU W to PBU U Production Pipeline Gas and Water Injection Pipelines to PBU W
	West End Test Well 21-11-12	1	-	-	-	-	-	1	
	Y Pad	29	-	-	9	-	-	38	Production Pipeline from PBU P PBU Y to PBU H Production Pipeline Gas and Water Injection Pipelines to PBU Y
	Z Pad SB	33	3	-	8	-	-	44	PBU Z to PBU U Production Pipeline Gas and Water Injection Pipelines to PBU Z
GC-3	A Pad	34	-	-	10	-	-	44	PBU A to GC3 Production Pipeline Gas and Water Injection Pipelines to PBU A
	B Pad	27	-	-	9	-	-	36	PBU B to GC3 Production Pipeline Gas and Water Injection Pipelines to PBU B
	C Pad	40	-	-	-	-	-	40	PBU C to GC3 Production Pipeline
	X Pad	30	-	-	10	-	-	40	PBU X to GC3 Production Pipeline Gas and Water Injection Pipelines to PBU X

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
Lisburne Production Center (GPMA)	L1	11	-	-	-	-	-	11	Production Pipeline from PBU W BEACH PBU LIS L1 to PBU LIS L2 Production Pipeline
	L2	14	-	-	-	-	-	14	Production Pipeline from PBU LIS L2 PBU LIS L1 to LPC Production Pipeline
	L3	13	-	-	-	-	-	13	Production Pipeline from PBU LIS L4 Production Pipeline from PBU LIS L5 PBU LIS L3 to LPC Production Pipeline
	L4	11	-	-	-	-	-	11	PBU LIS L4 to PBU LIS L3 Production Pipeline
	L5	23	-	1	1		-	25	PBU LIS L5 to PBU LIS L3 Production Pipeline Gas and Water Injection Pipelines to PBU LIS L5
	LG1	3	-	3	-	-	-	6	LG1 Production Pipeline Gas Injection Pipeline from LG1
	Lisburne Production	18	6	-	-	-	-	24	Lisburne Production Pipeline Water Injection Pipeline from Lisburne
	LPC-1	-	-	-	-	2	-	2	
	Niakuk	18	9	-	-	-	-	27	Production Pipeline from drillsite PBU NIAKUK to Niakuk Processing Facility Water Injection Pipeline to PBU NIAKUK

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
Lisburne Production Center (GPMA) (cont.)	PM-1 Pt McIntyre	18	2	1	3	-	-	24	PBU PT MAC P1 to LPC Production Pipeline Gas and Water Injection Pipelines to PBU PT MAC P1
	PM-2 Pt McIntyre	44	7	-	3	-	-	54	PBU PT MAC P2 to LPC Production Pipeline Gas and Water Injection Pipelines to PBU PT MAC P2
	West Beach	3	1	-	-	-	-	4	PBU W_BEACH to PBU LIS L1 Production Pipeline Water Injection Pipeline to PBU W_BEACH
Prudhoe Bay Unit Gas Handling Facilities									
Central Gas Facility (CGF) Central Compression Plant (CCP)	NGI Pad	-	-	14	-	-	-	14	
	WGI Pad	-	-	8	-	-	-	8	
	AGI Pad	-	-	10	-	-	-	10	
Prudhoe Bay Unit Supporting Facilities									
Central Power Station (CPS) Crude Oil Topping Unit (COTU) Skid 50 Seawater Intake and Treating Plant (STP) Seawater Injection Plant (SIP) Seawater Injection Plant West	N/A								

Facility	Drillsites / Wellpads / Other	Number of Wells							Associated Pipelines
		OIL	WINJ	GINJ	WAGIN	WDSP	OTHER	TOTAL	
Waste Disposal/Service Wells	GC-3B	-	-	-	-	6	-	6	
	G&I Plant	-	-	-	-	3	-	3	
	PWDW	-	-	-	-	4	-	4	
	EPA Oil Waste	-	-	-	-	3	-	3	
	WDSP	-	-	-	-	1	-	1	
	EDOKW Pad	-	7	-	-	-	-	7	
Duck Island Unit									
Endicott Production Facility	MPI	44	14	5	3	2	-	68	Endicott Pipeline from MPI to FS2 Gas and Water Injection Pipelines to MPI
	SDI	33	7	-	3	-	-	43	Endicott Pipeline from SDI to FS2 Endicott Pipeline Gas and Water Injection Pipelines to SDI
Northstar Unit									
Northstar Production Facility	Northstar	20	-	6	-	2	-	28	NORTHSTAR_UNIT Production Pipeline from drillsite NORTHSTAR_UNIT to Northstar Processing Facility Gas and Water Injection Pipelines to NORTHSTAR_UNIT
Badami Unit									
Badami Facility	Badami Field	11	-	1	-	1	-	13	BADAMI Drillsite to Endicott Pipeline Gas Injection Pipeline to BADAMI
NORTH SLOPE TOTAL # WELLS		2511	387	51	671	43	6	3671	

Note 1: Well data was obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) public databases FTP site for the August 2008 reporting period. [6]

Note 2: Well types include the following: Oil, Water Injection (WINJ), Gas Injection (GINJ), Water Alternating Gas Injection (WAGIN), Waste Disposal (WDSP), and Other. "Other" includes all wells that do not fall into these categories, such as comingled wells and multiple purpose wells (e.g. they perform more than one function such as gas injection and oil production).

Note 3: Wells that have been plugged and abandoned, administratively abandoned, or have permits that are expired, inactive, or withdrawn by the operator, or are otherwise not pertinent to the project scope are not included in the well counts in this table. These wells are considered to be out of scope. Plugged and abandoned wells may have previously been operational, but are not currently connected to existing infrastructure and are considered out of scope.

Table 4-2 Pipelines of the North Slope[6,10, 11, 12, 13, 14, 15, 16]

Pipeline Name / Description	Pipeline Operator	Product Transported	Pipeline Start	Pipeline Finish	Pipeline Diameter (inches)	Pipeline Length (miles)	2007 Pipeline Throughput	Year of Original Pipeline Construction	Maximum Allowable Operating Pressure
Alpine Diesel Pipeline	ConocoPhillips Alaska, Inc	Arctic Heating Fuel (AHF); other products	Kuparuk CPF2	Alpine CF	2.375	34	42,669,445 barrels	1998-1999	1,366 psig at 100° F
Alpine Oil Pipeline (APL)	Alpine Transportation Co.	Sales Oil	Alpine CF	Kuparuk CPF2	14	34	45,485,052 net barrels	1998-1999	2,064 psig at 180° F
Alpine Utility Pipeline	ConocoPhillips Alaska, Inc	Seawater **Prior to 2001, NGL*	Kuparuk CPF2	Alpine CF	12.75	34	4,246,068 gal AHF	1998-1999	2,160 psig at 150° F
Badami Sales Oil Pipeline * Warm Storage	BPXA	Sales Oil	Badami CPF	Badami Tie-in Pad at Endicott Pipeline	12	25	221,205 net barrels	1998	1,415 psig at 150° F (design)
Badami Utility Pipeline * Warm Storage	BPXA	NGL	Endicott MPI	Badami CPF	6	31	43,252 Mscf *used to push decommissioning pigs on sales oil pipeline	1998	Not in service
Endicott Pipeline	BPXA	Sales Oil	Endicott MPI	TAPS Pump Station 1	16	26	5,957,551 net barrels	1987	1,200 psig at 180° F (operating)
Greater Prudhoe Bay (NGL)	BPXA	NGL	-	-	-	-	-	-	-
Kuparuk Oil Pipeline (KPL)	Kuparuk Transportation Company	Sales Oil	Kuparuk CPF1	TAPS Pump Station 1	24, 16, & 14	28	114,796,833 barrels	1980	1,415 psig at 150° F

Pipeline Name / Description	Pipeline Operator	Product Transported	Pipeline Start	Pipeline Finish	Pipeline Diameter (inches)	Pipeline Length (miles)	2007 Pipeline Throughput	Year of Original Pipeline Construction	Maximum Allowable Operating Pressure
Kuparuk Pipeline Extension	Kuparuk Transportation Company	Sales Oil	Kuparuk CPF2	Kuparuk CPF1	12 & 18	9	77,665,001 barrels	1983	1,415 psig at 150° F
Milne Point Oil Pipeline (MPPL)	BPXA	Sales Oil	MPU CPF	Tie-in to Kuparuk Pipeline	14	10	13,290,709 net barrels	1985	1350 psig up to 200° F
Milne Point Products Pipeline (aka Kuparuk Enhanced Oil Recovery) ** Warm Shutdown as of 2002 - to be de-inventoried*	BPXA	NGL	Oliktok Pipeline	MPU CPF	8	10	Not in service	2000	Not in service
Northstar Natural Gas Pipeline	BPXA	Natural Gas	GPB CCP	Northstar Island Processing Facility	10	16	29 billion cubic feet	2001	1,480 psig
Northstar Oil Pipelines (Two pipelines bundled)	BPXA	Sales Oil	Northstar Island Processing Facility	TAPS Pump Station 1	10	17	18,881,267 net barrels	2001	1,480 psig at 100° F
Oliktok Pipeline (OPL)	Oliktok Pipeline Company	NGL **Prior to 1984, Sales Oil*	Adjacent to Skid 50 at TAPS PS01	Kuparuk CPF1	8, 10, & 16	28	9,806,123 barrels	1981	1,415 psig at 150° F
Oooguruk Pipeline	Pioneer	Multiphase (Oil, Gas and Produced Water)	Oooguruk Island	Oooguruk Tie-In Pad	12	8	-	2007	-

Pipeline Name / Description	Pipeline Operator	Product Transported	Pipeline Start	Pipeline Finish	Pipeline Diameter (inches)	Pipeline Length (miles)	2007 Pipeline Throughput	Year of Original Pipeline Construction	Maximum Allowable Operating Pressure
Prudhoe Bay Western Operating Area Oil Transit Pipeline	BPXA	Crude Oil	FS-2	TAPS Pump Station 1	-	-	-	2008	-
Prudhoe Bay Eastern Operating Area Oil Transit Pipeline	BPXA	Crude Oil	GC-2	TAPS Pump Station 1	-	-	-	2008	-

Note 1: Blank fields (shown with a dash) in this table represent information that has not been located as of February 1, 2009. Infrastructure component information will continue to be compiled as it becomes available.

4.2 Cook Inlet

The scope of the Cook Inlet infrastructure region included in this project begins at the wellbore, both for offshore platforms and onshore oil and gas facilities and ends at the point of distribution. Major Cook Inlet infrastructure components included within the scope are listed below and are shown visually in Figure 4-3 and in Appendix A.

- Offshore Oil and Gas Production Platforms – Sixteen offshore platforms which service the production oil and gas, including process equipment, facility piping and associated pipelines. *Four platforms are currently in lighthouse mode (i.e., wells shut in, production facilities cleaned, decommissioned but not removed, and navigational aids intact*), *and are not producing, but will be considered as part of the scope.*

- Onshore Production/Processing Facilities (Platform Support) – Five onshore oil and gas processing facilities, including East Forelands Facility, Granite Point Tank Farm, Trading Bay Production Facility, West McArthur River Facility, and Kustatan Facility (scope includes process equipment, facility piping and associated pipelines).

- Onshore Central Oil and Gas Production Facilities – Numerous onshore gas production facilities, including all process equipment, facility piping and associated pipelines.

- Terminal Facility – Drift River Marine Terminal and associated Christy Lee Platform, including process equipment, facility piping and associated pipelines up to the berth loading arms.

- Associated Pipelines

Out of scope components include the following:

- Units –Units that are currently not producing because they are inactive, in development or exploration, or are shut-in and disconnected from the existing infrastructure include Cosmopolitan, Corsair, Kitchen, Nikolaevsk, North Alexander, North Fork, and South Ninilchik.

- Beluga Gas Transmission Pipeline and downstream distribution – The 20 inch natural gas pipeline transports natural gas from the Beluga gas fields on the west side of Cook Inlet to downstream power generation and heating users.

- Kenai to Anchorage Gas Transmission Pipeline – The 12 inch pipeline transports gas from Kenai Peninsula gas fields to downstream users in Anchorage.

- Beluga Power Plant – Considered in scope only as an infrastructure feed source (power to some facilities is in scope).

- Nikiski Industrial Complex – Nikiski facilities associated with downstream processing and distribution include the Tesoro Refinery, LNG Plant, Gas to Liquids Plant, and Fertilizer Plant. The Nikiski Terminal to Tesoro Refinery Pipeline and the Nikiski Pipeline, which transports refined petroleum from Tesoro's Kenai Refinery to the Port of Anchorage, are out of scope.

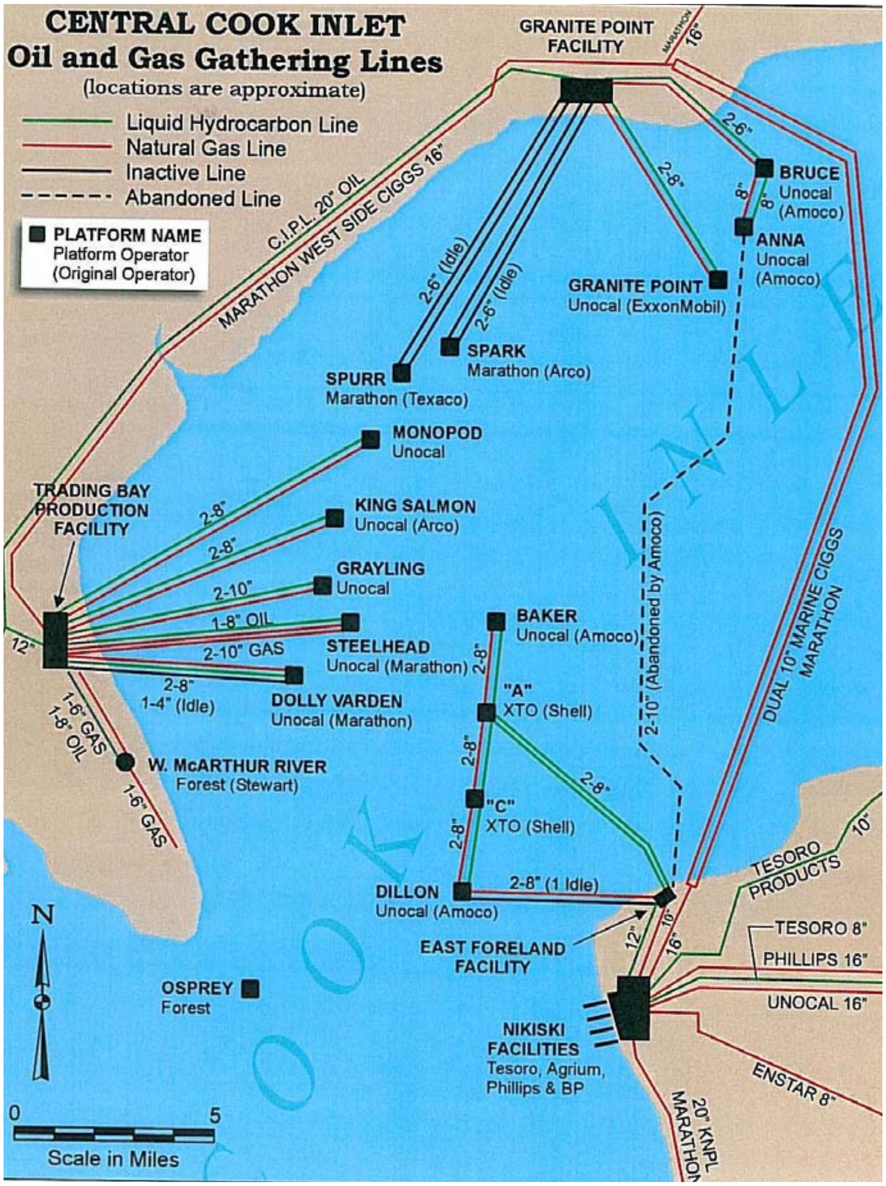

Figure 4-3 Cook Inlet Infrastructure[17]

Note: This map does not include all pipelines and other components, or the North Cook Inlet, but is included as a point of reference for discussion in this section. A detailed Cook Inlet Infrastructure map is included in Appendix A.

Table 4-3 contains the detailed scope of Cook Inlet facilities and components included in the project based on a review of publicly available data. Cook Inlet pipelines are shown in Table 4-4.

Table 4-3 Physical Scope of Cook Inlet Infrastructure[6]

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
Offshore Facilities											
Operating Oil and Gas Production Platforms											
Anna Platform		14	-	13	-	1	-	-	-	28	8 in. Gas Pipeline to Bruce Platform 8 in. Oil Pipeline to Bruce Platform
Bruce Platform		9	3	3	-	-	1-	-	-	15	8 in. Gas Pipeline to the Granite Point Production Facility 8 in. Oil Pipeline to the Granite Point Production Facility 8 in. Gas Pipeline to Anna Platform 8 in. Oil Pipeline to Anna Platform
Dolly Varden Platform		23	1	10	-	-	-	-	2	36	4 in. Gas Pipeline to the Trading Bay Production Facility 8 in. Produced Water/ Oil Pipeline to the Trading Bay Production Facility
Granite Point Platform		10	-	7	-	-	1	-	-	18	8 in. Gas Pipeline to the Granite Point Production Facility 8 in. Oil Pipeline to Bruce Platform

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
Grayling Platform		20	2	13	-	-	-	-	2	37	8 in. Gas Pipeline to the Trading Bay Production Facility 10 in. Produced Water/ Oil Pipeline to Trading Bay
King Salmon Platform		11	2	7	-	-	-	-	2	22	8 in. Gas Pipeline to the Trading Bay Production Facility 8 in. Produced Water/ Oil Pipeline to the Trading Bay Production Facility
Middle Ground Shoal (MGS) A Platform		24	-	7	-	-	1	-	3	35	8 in. Gas Pipeline to Baker Platform Gas Pipeline to MGS C Platform 8 in. Oil Pipeline to the XTO Energy Inc. East Forelands Facility 8 in. Produced oil/gas/water emulsion pipeline to Baker Platform (inactive) Produced oil/gas/water emulsion pipeline to MGS C Platform
MGS C Platform		17	-	7	-	-	1	-	-	25	8 in. Gas Pipeline to MGS A Platform Gas Pipeline to Dillon Platform (inactive) 8 in. Produced oil/gas/water emulsion subsea pipeline to MGS A Platform Produced oil/gas/water emulsion subsea pipeline to Dillon Platform (inactive)

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
Monopod Platform		20	1	6	-	-	-	-	5	32	8 in. Gas Pipeline to the Trading Bay Production Facility 8 in. Produced Water/ Oil Pipeline to the Trading Bay Production Facility
Osprey Platform		4	1	1	-	-	1	-	-	7	Gas Pipeline to the Kustatan Production Facility Oil Pipeline to the Kustatan Production Facility Water Pipeline from Kustatan to Osprey Platform
Steelhead Platform		1	14	2	-	-	-	-	6	23	10 in. Gas Pipeline to the Trading Bay Production Facility 8 in. Produced Water/ Oil Pipeline to the Trading Bay Production Facility
North Cook Inlet Platform (Tyonek)		-	12	-	-	-	-	-	2	14	10 in. North Cook Inlet Gas Pipeline to the tie-in at the 16 in. North Cook Inlet Gas Pipeline (routes to Port Nikiski Facilities & Terminals) 10 in. North Cook Inlet pipeline tie-in to the Nikiski Pipeline (a record exists for this second pipeline, however the status is unknown)

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
Non-Operating Oil and Gas Production Platforms											
Baker Platform	Note: Although Baker Platform is listed as in "lighthouse" mode, it has a single active well that is producing, Baker 14.	9	3	10	-	-	-	-	1	22	8 in. Gas Pipeline to MGS A Platform 8 in. Produced oil/gas/water emulsion pipeline to MGS A Platform
Dillon Platform		10	-	6	-	-	-	-	-	16	8 in. Gas Pipeline to MGS C Platform 8 in. Oil Pipeline to MGS C Platform
Spark Platform		-	1	-	-	-	2	5	-	8	6 in. Gas Pipeline to the Granite Point Production Facility 6 in. Oil Pipeline to the Granite Point Production Facility
Spurr Platform		-	-	-	-	-	-	1	-	1	6 in. Gas Pipeline to the Granite Point Production Facility 6 in. Oil Pipeline to the Granite Point Production Facility
Onshore Oil and Gas Platform Support Facilities											
Trading Bay Facility	Dolly Varden Platform	*See platform for associated wells and pipelines*									16 in. West Side Gas Pipeline to the Granite Point Production Facility 20 in. Cook Inlet Oil Pipeline (CIPL) to Drift River Marine Terminal Redoubt Oil Pipeline from Kustatan and West McArthur
	Grayling Platform	*See platform for associated wells and pipelines*									
	King Salmon Platform	*See platform for associated wells and pipelines*									
	Monopod Platform	*See platform for associated wells and pipelines*									

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
	Steelhead Platform	*See platform for associated wells and pipelines*									
XTO East Forelands Facility	MGS A Platform	*See platform for associated wells and pipelines*									16 in. Gas Pipeline North Cook Inlet 12 in. MGS Oil Pipeline to the Tesoro Refinery 10 in. Oil Pipeline North Cook Inlet
	MGS C Platform	*See platform for associated wells and pipelines*									
	Dillon Platform (inactive)	*See platform for associated wells and pipelines*									
	Baker Platform (inactive)	*See platform for associated wells and pipelines*									
Kustatan Production Facility	Osprey Platform	*See platform for associated wells and pipelines*									Redoubt Gas Pipeline from the Osprey Platform Redoubt Oil Pipeline from the Osprey Platform Water Pipeline to Osprey Platform Redoubt Oil Pipeline to the Trading Bay Production Facility
Granite Point Tank Farm	Anna Platform	*See platform for associated wells and pipelines*									10 in. Cook Inlet Gas Gathering System (CIGGS) to Port Nikiski Facilities & Terminals 16 in. Gas Pipeline to the Trading Bay Production Facility
	Bruce Platform	*See platform for associated wells and pipelines*									
	Granite Point Platform	*See platform for associated wells and pipelines*									

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
	Spark Platform (inactive)	*See platform for associated wells and pipelines*									Tie-in to the 20 in. Beluga Gas Transmission Pipeline
	Spurr Platform (inactive)	*See platform for associated wells and pipelines*									
Onshore Oil and Gas Production Facilities											
West Side											
Beluga River	Beluga	-	19	-	-	-	1		-	20	Gas Pipeline(s) to the tie in at the 20 in. Beluga Gas Transmission Pipeline and pipelines to the Beluga Generation Plant
Ivan River	Ivan River	-	4	-	-	-	1	-	-	5	8 in. Gas Pipeline to the tie-in at the 20 in. Beluga Gas Transmission Pipeline
Lewis River	Lewis River	-	3	-	-	-	1	-	-	4	Gas Pipeline to the tie-in at the 20 in. Beluga Gas Transmission Pipeline
Lone Creek	Lone Creek	-	2	-	-	-	-	-	-	2	6” Gas Pipeline to the tie-in at the 20 in. Beluga Gas Transmission Pipeline
Moquawkie	Moquawkie	-	1	-	-	-	-	-	-	1	6 in. Gas Pipeline to the Granite Point Production Facility[3]
Nicolai Creek	63279	-	1	-	-	-	-	-	-	1	4 in. Gas Pipeline to the Granite Point Production Facility
	17598	-	1	-	-	-	-	-	-	1	

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
	17585	-	2	-	-	-	-	-	-	2	16 in. Gas Pipeline to the Granite Point Production Facility 10 in. Oil Pipeline to the Granite Point Production Facility
Pretty Creek	Pretty Creek	-	1	-	-	-	-	-	1	2	8 in. Gas Pipeline to the tie-in at the 20 in. Beluga Gas Transmission Pipeline
Stump Lake	Stump Lake	-	1	-	-	-	-	-	-	1	6 in. Gas Pipeline to the tie-in at the 8 in. Ivan River Gas Pipeline (which ties into the 20 in. Beluga Gas Transmission Pipeline)
W. Foreland	W Foreland	-	2	-	-	-	-	-	-	2	Redoubt Oil Pipeline to the Trading Bay Production Facility
W McArthur River	W McArthur River	5	-	-	-	-	1	-	-	6	Redoubt Oil Pipeline to the Trading Bay Production Facility
East Side											
Beaver Creek	Beaver Creek Unit	2	11	-	-	-	1	-	-	14	12 in. Gas Pipeline to Port Nikiski Facilities & Terminals
	Wolf Lake	-	2	-	-	-	-	-	-	2	12 in. Pipeline to the tie-in to the Beaver Creek Pipeline
Kenai CLU	Kenai Cannery Loop	-	10	-	-	-	-	-	-	10	12 in. Kenai Gas Pipeline to Port Nikiski Facilities & Terminals 12 in. Kenai Kachemak Gas Pipeline to Port Nikiski Facilities & Terminals

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
Deep Creek Happy Valley	Happy Valley Pad A	-	10	-	-	-	1	-	-	11	12 in. Kenai Kachemak Gas Pipeline to Port Nikiski Facilities & Terminals
	Happy Valley Pad B	-	-	-	-	-	-	-	-	-	
Kasilof	Kasilof	-	1	-	-	-	-	-	-	1	12 in. Kenai Kachemak Gas Pipeline to Port Nikiski Facilities & Terminals
Kenai Gas Facility	Kenai Beluga	-	21	-	-	-	-	-	3	24	12 in. Gas Pipeline to Kenai-Kachemak Pipeline 12 in. Kenai Kachemak Gas Pipeline to Port Nikiski Facilities & Terminals
	Kenai Deep	-	3	-	-	-	-	-	2	5	
	Kenai Tyonek	-	5	-	-	-	-	-	1	6	
	Kenai Unit	-	15	-	-	-	3	-	9	27	
Ninilchik FC	Ninilchik FC	-	3	-	-	-	-	-	-	3	Kenai Kachemak Gas Pipeline to Port Nikiski Facilities & Terminals
Ninilchik GO	Ninilchik GO	-	5	-	-	-	-	-	-	5	
Ninilchik SD & PAX WELLS	Ninilchik SD & PAX WELLS	-	7	-	-	-	-	-	-	7	
Ninilchik A	Ninilchik A	-	3	-	-	-	-	-	-	3	
Sterling	Sterling Unit	-	2	-	-	-	1	-	-	3	Gas Pipeline to tie-in at Kenai to Anchorage Gas Transmission Pipeline
Swanson River Field/SRU	34-10	1	8	-	-	-	-	-	-	9	16 in. Swanson River Gas Pipeline to Port Nikiski Facilities & Terminals 8.625 in. Swanson River Oil Pipeline to Port Nikiski Facilities & Terminals
	Center	5	3	-	1	2	2	-	-	13	
	SCU	31	6	-	-	2	1	-	1	41	

Facility	Drillsites / Wellpads	Number of Wells[1]									Associated Pipelines
		OIL	GAS	WINJ	GINJ	GSTOR	WDSP	SI[2]	OTHER	Total	
W. Fork	West Fork CIRI	-	3	-	-	-	-	-	-	3	3" West Fork Gas Pipeline to the tie-in at the 12" Kenai to Anchorage Gas Transmission Pipeline

Note 1: Well data was obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) public databases FTP site for the August 2008 reporting period.

Note 2: Well types include the following: Oil, Gas, Water Injection (WINJ), Gas Injection (GINJ), Gas Storage, Waste Disposal (WDSP) and Other. "Other" includes all wells that do not fall into these categories, such as comingled wells and multiple purpose wells (e.g. they perform more than one function such as gas injection and oil production).

Note 3: Wells that have been plugged and abandoned, administratively abandoned, or have permits that are expired, inactive, or withdrawn by the operator, or are otherwise not pertinent to the project scope are not included in the well counts in this table. These wells are considered to be out of scope. Plugged and abandoned wells may have previously been operational, but are not currently connected to existing infrastructure and are considered out of scope.

Note 4: Shut-in wells are inactive but may be connected to existing infrastructure and are included in this table.

Note 5: Pipelines from Onshore Oil and Gas Production Facilities, which may be smaller facilities that have their own processing equipment on the drillsite/wellpad, may be routed to/through Onshore Oil and Gas Platform Support Facilities.

Note 6: Industry data suggests that Baker Platform is inactive, but one well is currently producing.

Table 4-4 Pipelines of the Cook Inlet[6,12,10, 13, 18, 19]

Pipeline Name / Description	Pipeline Operator	Product Transported	Pipeline Start	Pipeline Finish	Pipeline Diameter (inches)	Pipeline Length (miles)	Pipeline Throughput	Year of Original Pipeline Construction	Maximum Allowable Operating Pressure
Cook Inlet Gas Gathering System (CIGGS)	Chevron, Marathon	Gas	Granite Point Production Facility	Port Nikiski Facilities & Terminals	10	-	-	-	-
Cook Inlet Gas Gathering System (CIGGS) / West Side Gas Pipeline	Chevron, Marathon	Gas	Trading Bay Facility	Granite Point Production Facility	16	-	-	-	-
Cook Inlet Pipeline (CIPL)	Cook Inlet Pipeline Company	Crude Oil	Granite Point Production Facility	Drift River Marine Terminal	20	42	-	1966	960 psi (design)
Kenai Gas Pipeline (KPL)	Kenai Kachemak Pipeline, LLC	Natural Gas	Kenai Gas Field	Port Nikiski Facilities & Terminals	10	-	-	-	-
Kenai Kachemak Gas Pipeline (KKPL)	Marathon Pipe Pipeline, LLC	Natural Gas	Happy Valley Facilities	Marathon Oil Company 500 Master Meter Building	12	33	22.65 billion cubic feet (2007)	2003	1,480 psig
Middle Ground Shoal (MGS) Pipeline	Kenai Pipeline Company	Crude Oil	XTO E. Forelands Facility	Port Nikiski Facilities & Terminals	12	4	-	1965	600
North Cook Inlet Gas Pipeline	ConocoPhillips Alaska	Natural Gas	Tyonek Platform	Port Nikiski Facilities & Terminals	16	-	-	-	-

Pipeline Name / Description	Pipeline Operator	Product Transported	Pipeline Start	Pipeline Finish	Pipeline Diameter (inches)	Pipeline Length (miles)	Pipeline Throughput	Year of Original Pipeline Construction	Maximum Allowable Operating Pressure
Swanson River Pipeline	Kenai Pipeline Company	Crude Oil	Swanson River	Port Nikiski Facilities & Terminals	8.625	19	-	1960	-

Note 1: Blank fields (shown as dashes) in this table represent information that has not been located as of February 1, 2009. Infrastructure component information will continue to be compiled as it becomes available.

4.3 Trans Alaska Pipeline System

The TAPS infrastructure region begins at the inlet remotely operated valves (ROVs) from the North Slope supply pipelines to Pump Station 1 and continues through the pipeline and associated pump stations to the VMT, up to the marine terminal loading arms. The major TAPS infrastructure components included in the scope of this project are listed below and are shown in Figure 4-4.

- Trans Alaska Pipeline
- Fuel Gas Line
- Pump Stations
- Valdez Marine Terminal

Out of scope components include the following:

- Flint Hills Refinery (located in North Pole)*
- Petro Star Refineries (located in North Pole and Valdez)*

**Downstream infrastructure, including refineries are excluded from the scope of this project but may be a focus of future study. Crude oil pipelines to these facilities are considered in scope up to the metering valves on the refinery feed and outlet lines only. Although impacts to refineries will not be considered, a shutdown of a refinery has the potential to act as an initiating event and will be considered in those terms.*

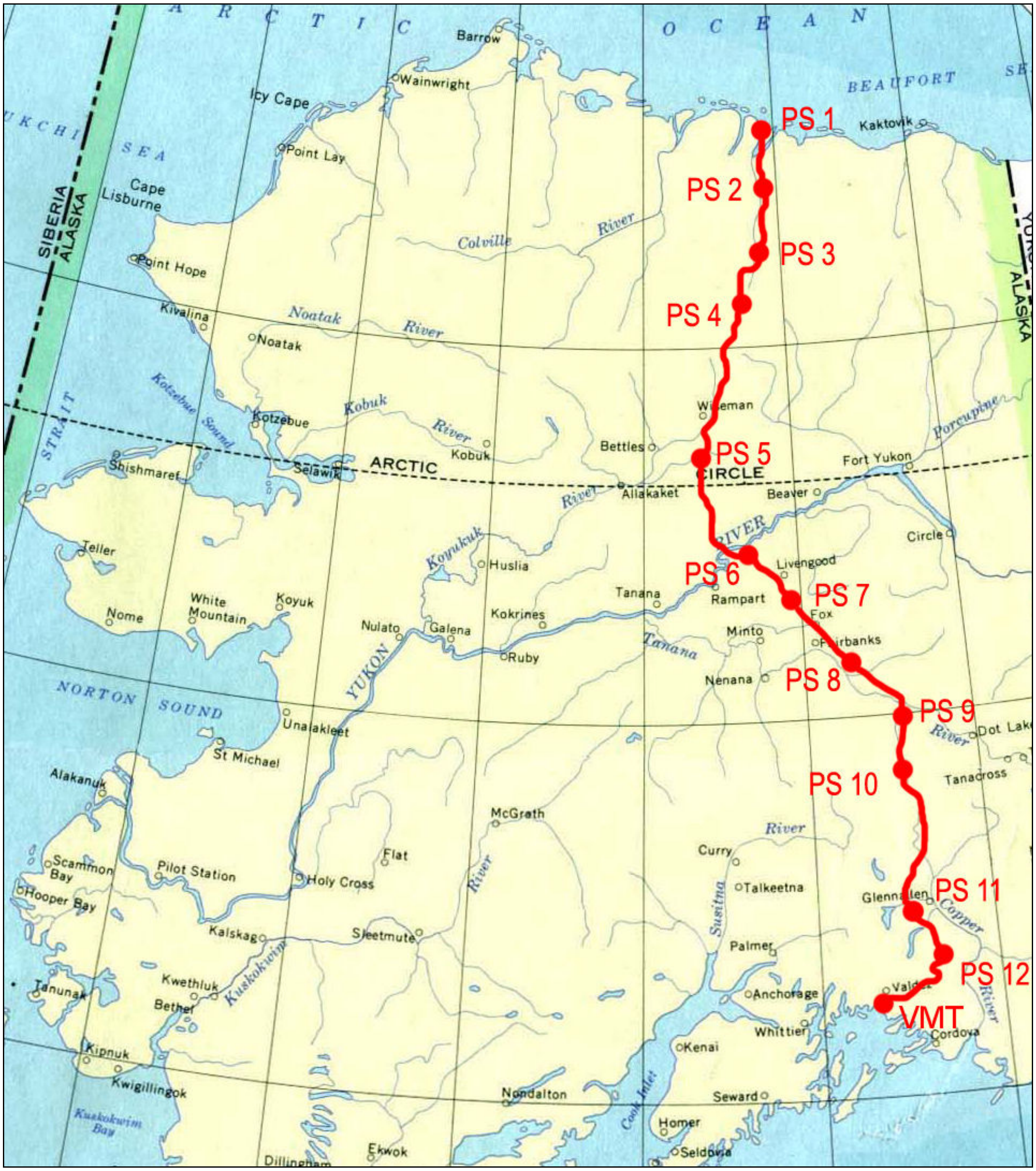

Figure 4-4   TAPS Pipeline[20]

Table 4-5 contains a listing of TAPS facilities and components that have been determined to be in the project scope based on a review of publicly available data.

Table 4-5 Detailed Physical Scope of TAPS Infrastructure

Component	Major Equipment[21,22,23, 24]
Pump Station Facilities	
Pump Station 1 *(MP 0)*	Pumping System/Major Equipment: • 4 mainline crude oil turbine-driven pumps *(original pumps will be replaced as part of SR Project)* • 3 mainline booster pumps to boost oil pressure Utility/Support Systems: • Electrical/Power: PS 1 is connected to Prudhoe Bay's central power grid. *(Post-SR, PS 1 will remain on the Prudhoe Bay grid with the addition of 2 gas-turbine generators. Critical systems will have up to 4 hours of emergency power via an uninterruptible power supply (UPS) system, which can be extended by a small 65-kilowatt (kW) diesel generator)* • Fuel: Natural gas from North Slope fields. *(PS 1 also has 2 Gas Turbine Compressors to compress natural gas supplied from North Slope fields for the Fuel Gas Line)* • Refrigeration: Foundation Refrigeration Equipment • Storage Tanks: 2 Crude Oil Storage Tanks, 420,000 bbl total capacity • Metering Equipment • Drag Reducing Agent (DRA) injection facilities • Communications and Control: The TAPS-wide Operations Communications and Control System provide supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. - *Primary:* Microwave - *Backup:* Satellite - *Components*: Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)

Component	Major Equipment[21,22,23, 24]
	Associated Pipelines: The following five pipelines deliver oil to PS 1.[24] • *Sadlerochit*: Started up in 1977, carries oil from the Eastern Operating Area (EOA) and the Western Operating Area (WOA) Prudhoe Bay developments. • *Kuparuk:* Started up in December 1981; carries oil from the Kuparuk, Alpine, Milne Point, West Sak, Tabasco, and Tarn developments. • *Lisburne:* Started up in December 1986; carries oil from the Pt. McIntyre and Niakuk developments. • *Endicott:* Started up in October 1987; carries oil from the Endicott and Badami developments. • *Northstar:* Started up in November 2001; carries oil from Northstar Island

Pump Station 3 *(MP 104.27)*	Pumping System/Major Equipment:
	• 2 mainline crude oil electrically driven pumps
	• Booster pump(s) to move oil from storage tank to main line
	Utility/Support Systems:
	• Electrical/Power: Primary Power – Two 12.9-MW gas turbine generators that run on natural gas or liquid fuel. Backup Power – One 2,250-kW diesel generator fueled by arctic-grade diesel. Unit has a 24-volt battery for black start capability.
	• Fuel: Natural gas from North Slope fields or liquid fuel
	• Refrigeration: Foundation Refrigeration Equipment
	• Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity.
	• Heavy Equipment Maintenance Facility
	• Communications and Control: The TAPS-wide Operations Communications and Control System provide supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control.
	  - *Primary Communication System:* Microwave
	  - *Backup System*: Satellite
	  - *Components:* Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)

Component	Major Equipment[21,22,23, 24]
Pump Station 4 *(MP 144.05)*	<u>Pumping System/Major Equipment:</u> • 4 mainline crude oil turbine-driven pumps *(original pumps, will be replaced with electrically-driven pumps as part of SR Project)* • Booster pump(s) to move oil from storage tank to main line <u>Utility/Support Systems:</u> • Electrical/Power: *Two new turbine generators that run on natural gas or liquid fuel will be installed at PS 4 as part of SR Project. Diesel generators will be provided for back-up power at PS 4 in addition to up to 4 hours of emergency power via an uninterruptible power supply (UPS) system for critical systems. The emergency power will also be able to be extended by a small 65-kilowatt (kW) diesel generator.* • Fuel: Natural gas from North Slope fields • Refrigeration: Foundation Refrigeration Equipment • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity. • Communications and Control: The TAPS-wide Operations Communications and Control System provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. - Primary Communication System: Microwave - Backup System: Satellite - *Components*: Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)

Component	Major Equipment[21,22,23, 24]
Pump Station 9 *(MP 548.74)*	Pumping System/Major Equipment: • 2 mainline crude oil electrically driven pumps • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems: • Electrical/Power: Primary Power – PS 9 uses commercial power from the Golden Valley Electric Association, via a 138 kV tie-in line and a substation which provides up to 22 MW of power at the required 13.8 kV. Backup Power – Two 2,250-kW diesel generators supply 4.5 MW power, fueled by arctic-grade diesel. Critical systems will have up to 4 hours of emergency power via an uninterruptible power supply (UPS) system, which can be extended by a small 65-kilowatt (kW) diesel generator. • Fuel: Arctic-grade Diesel • Refrigeration: Foundation Refrigeration Equipment • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity. • Drag Reducing Agent (DRA) injection facilities • Communications and Control: The TAPS-wide Operations Communications and Control System provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. - Primary Communication System: Microwave - Backup System: Satellite - *Components:* Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)

Component	Major Equipment[21,22,23, 24]
Pump Station 5 *(MP 274.82)*	Operates as a Pressure Relief Station only Pumping System/Major Equipment: • Booster pump(s) to move oil from storage tank to main line • Injection Pumps Utility/Support Systems: • Electrical/Power: PS 5 is fueled by liquid turbine fuel *(Post SR, PS 5 will be powered by 4 reciprocating diesel generators providing both primary and backup power. Critical systems will have uninterruptable emergency power).* • Fuel: Liquid turbine fuel. • Refrigeration: Foundation Refrigeration Equipment • Storage Tanks: One Crude Oil Relief Tank, 150,000 bbl capacity. • Communications and Control: The TAPS-wide Operations Communications and Control System provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. - *Primary Communication System:* Microwave - *Backup System:* Satellite - *Components:* Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)

Component	Major Equipment[21,22,23, 24]
Ramped Down/Standby Pump Stations	
Pump Station 8 *(MP 489.28)*	Placed in ramped down status June 30, 1996 Pumping System/Major Equipment *(all equipment is out of service):* • 3 mainline turbine-driven pumps • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems *(all equipment is out of service):* • Electrical/Power: Powered by turbines that use liquid fuel and commercially generated power from local providers • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Topping unit in standby: Production capacity 2,400 avg. bbl./day of low sulfur turbine fuel • Communications and Control: N/A as PS 2 is inactive
Pump Station 10 *(MP 585.83)*	Placed in ramped down status July 1, 1996 Pumping System/Major Equipment *(all equipment is out of service):* • 3 mainline turbine-driven pumps • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems *(all equipment is out of service):* • Electrical/Power: Powered by turbines that use liquid fuel • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Topping unit in standby: Production capacity 2,400 avg. bbl./day of low sulfur turbine fuel • Communications and Control: N/A as PS 2 is inactive

Component	Major Equipment[21,22,23, 24]
Pump Station 2 *(MP 57.76)*	Placed in ramped down status July 1, 1997, decommissioned and isolated from main line August 17, 2008 Pumping System/Major Equipment *(all equipment is out of service):* • 2 mainline pumps disconnected entirely Utility/Support Systems *(all equipment is out of service):* • Electrical/Power: Powered by turbines that use liquid fuel • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Foundation Refrigeration Equipment • Communication and Control: N/A as PS 2 is inactive
Pump Station 6 *(MP 355)*	Placed in ramped down status August 8, 1997 Pumping System/Major Equipment *(all equipment is out of service):* • 3 mainline turbine-driven pumps • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems *(all equipment is out of service):* • Electrical/Power: Powered by turbines that use liquid fuel • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Foundation Refrigeration Equipment • Topping unit in standby: Production capacity 2,400 avg. bbl./day of low sulfur turbine fuel • Communications and Control: N/A as PS 2 is inactive

Component	Major Equipment[21,22,23, 24]
Pump Station 12 *(MP 735.10)*	Placed in ramped down status April 1, 2005, decommissioned and isolated from main line July 24, 2005 Pumping System/Major Equipment *(all equipment is out of service):* • 3 mainline pumps disconnected entirely • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems *(all equipment is out of service):* • Electrical/Power: Powered by turbines that use liquid fuel and commercially generated power from local providers • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Foundation Refrigeration Equipment • Communications and Control: N/A as PS 2 is inactive
Pump Station 7 *(MP 414.18)*	Placed in warm standby March of 2008 Pumping System/Major Equipment: • 2 mainline turbine-driven pumps • Booster pump(s) to move oil from storage tank to main line Utility/Support Systems: • Electrical/Power: Powered by turbines that use liquid fuel • Storage Tanks: One Crude Oil Relief Tank, 55,000 bbl capacity • Drag Reducing Agent (DRA) injection facilities • Communications and Control: N/A as PS 2 is inactive
Pump Station 11 *(MP 685.99)*	Never built; exists as a maintenance facility and security site

Component	Major Equipment[21,22,23, 24]
TAP Pipeline Segments	
PS 1 to PS 2	Major Equipment: • Piping – piping length is 57.76 mi; 48” diameter • Valves • Pig Launching/Receiving Facilities at PS 1 Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. • Diversion Lines: N/A
PS 2 to PS 3	Major Equipment: • Piping – piping length is 46.51 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A

Component	Major Equipment[21,22,23, 24]
PS 3 to PS 4	Major Equipment: • Piping – piping length is 39.78 mi; 48” diameter • Valves • Pig Launching/Receiving Facilities at PS 4 Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A
PS 4 to PS 5	Major Equipment: • Piping – piping length is 130.77 mi; 48” diameter • Valves • Pig Launching/Receiving Facilities at PS 4 Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A
PS 5 to PS 6	Major Equipment: • Piping – piping length is 80.18 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A

Component	Major Equipment[21,22,23, 24]
PS 6 to PS 7	Major Equipment: • Piping – piping length is 59.18 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A
PS 7 to PS 8	Major Equipment: • Piping – piping length is 75.1 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: The GVEA Pipeline located in North Pole is a 4.6-mile loop from the TAP to the Flint Hills Resources and Petro Star Inc. refineries; the pipe is 14-inch from TAPS to the refineries and the return pipe to TAPS is 16-inch. There are two metering stations in North Pole. One metering station is owned by APSC and is located where the GVEA Pipeline connects to the TAPS and the second metering station is located near the refineries. *The scope of the risk assessment ends at the inlet metering valves to these facilities.*

Component	Major Equipment[21,22,23, 24]
PS 8 to PS 9	Major Equipment: • Piping – piping length is 59.46 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A
PS 9 to PS 10	Major Equipment: • Piping – piping length is 37.09 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A
PS 10 to PS 11	Major Equipment: • Piping – piping length is 100.16 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Refrigeration: 3 MRU locations between PS 10 and PS 11 totaling approximately 4 miles • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: N/A

Component	Major Equipment[21,22,23, 24]
PS 11 to PS 12	Major Equipment: • Piping – piping length is 49.11 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: A pipeline transports crude oil from the TAPS to the Petro Star, Inc. Refinery in Valdez. The Valdez Petro Star Inc. metering station is located just prior to where the TAP ends at the VMT in Valdez.
PS 12 to VMT	Major Equipment: • Piping – piping length is 65.22 mi; 48” diameter • Valves Utility/Support Systems: • Electrical/Power: Local propane-fueled energy converters. Local battery banks are also installed for back-up power for valves. • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. Diversion Lines: A pipeline transports crude oil from the TAPS to the Petro Star, Inc. Refinery in Valdez. The Valdez Petro Star Inc. metering station is located just prior to where the TAP ends at the VMT in Valdez.
Fuel Gas Pipeline Segments	
PS1 to MP 34	Major Equipment: • Piping – piping length is 34 mi; 10” diameter (generally parallels mainline crude oil pipeline) • Valves • Pig Launching/Receiving Facilities at PS 1, MP 34, and PS 4 • Two gas turbine compressors at PS 1 boost gas pressure from ~600 psi. Utility/Support Systems: • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control.

Component	Major Equipment[21,22,23, 24]
MP 34 to PS 4	Major Equipment: • Piping – piping length is 110 mi; 8" diameter (generally parallels mainline crude oil pipeline) • Valves • Pig Launching/Receiving Facilities at PS 1, MP 34, and PS 4 Utility/Support Systems: • Communications and Control: provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control.
Valdez Marine Terminal	
Ballast Water Treatment (BWT) Facility	Major Equipment: • 3 Settling tanks; capacity of 430,000 bbl. each, 53 feet 6 inches high and 250 feet in diameter. • 2 Biological Treatment Tanks, aboveground, concrete; capacity: 5.8 million gallons each
Vapor Recovery Systems and Power Generation (Power/Vapor Facility)	Major Equipment: • 5 gas compressors: Two of the compressors dedicated to Berths, two compressors dedicated to tank farm service, and one operates as a swing compressor between the tank and the berths. • Crude Oil Tank Collection System • Tanker Vapor Collection System • 3 Waste Gas Incinerators • Flue Gas and Scrubber System • Inert Gas Cooler • Nitrogen Skid • Compressed Air System • Power Plant (3 steam boilers, 3 turbine driven generators, 2 standby diesel generators, 4 battery-supplied UPS systems)
Marine Loading Facility *(up to berth loading arms)*	Major Equipment: • *4 Berths:* Berths 1, 3, 4 and 5 (Berths 4 and 5 are fixed platforms equipped with vapor recovery arms. Berth 3 is used as a lay berth for tankers. Berth 1 is out of service, but is a floating platform originally designed to handle smaller tankers (12,000-16,000 deadweight tons).25 • *Loading Arms:* Four16-in arms on Berths 3, 4 and 5.

Component	Major Equipment[21,22,23, 24]
Crude Oil Storage Tanks	<u>Major Equipment:</u> • East Tank Farm – 14 Crude Oil Storage Tanks • West Tank Farm – 4 Crude Oil Storage Tanks, (*only 1 is currently active*) • Tank Capacity: 510,000 bbl ea.; 6.2 mm bbl total working volume
Utility/Support Systems	• Fuel (Gas, Diesel) • Communications and Control: The TAPS-wide Operations Communications and Control System provides supervisory control and telemetering, seismic monitoring, and remote gate valve status monitoring and control. - *Primary Communication System:* Microwave - *Backup System:* Satellite - *Components:* Backbone Communication System, Remote Gate valve, Alternate Route Communications Systems (ARCS) (a private radio network that is used by technicians across TAPS)
Other Facilities	• Pig Receiving Facility • Crude Oil Metering Facilities

5 RISK ASSESSMENT ORGANIZATIONAL STRUCTURE AND DATA MANAGEMENT

The overall Alaska Oil and Gas Infrastructure is comprised of the three main infrastructure regions shown below in Figure 5-1.

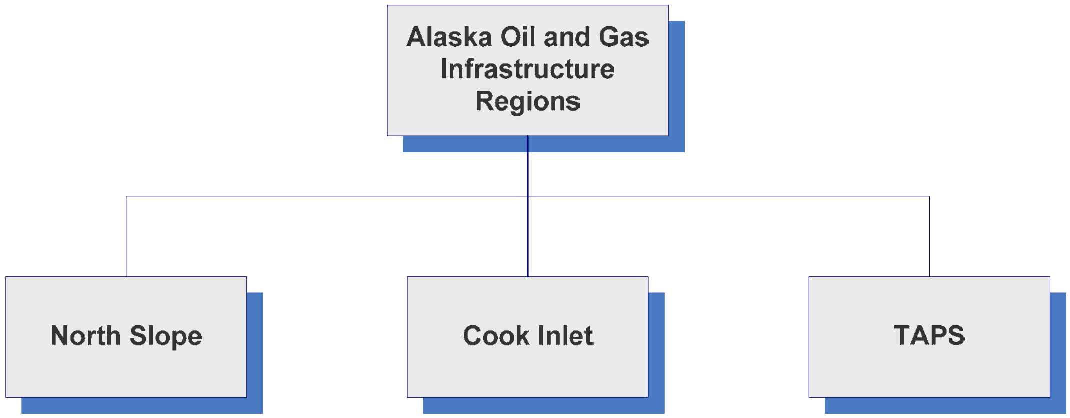

Figure 5-1 Alaska Oil and Gas Infrastructure Regions

The North Slope and Cook Inlet infrastructure regions include numerous operating areas or units with multiple types of facilities which support the production and processing of oil and gas from the fields in the region. TAPS is comprised of pump station facilities and the piping segments between those facilities, as well as the Valdez Marine Terminal. A listing of facilities and their major components (major equipment and/or systems that make up or are associated with those facilities) was developed for each operating area or unit that is considered to be in the scope of the risk assessment for the North Slope and Cook Inlet. A comprehensive list of in-scope facilities for the three infrastructure regions is included in Section 4 of this report.

In order to implement the risk assessment methodology in a systematic way, the overall infrastructure will be divided into smaller segments or nodes to execute the risk analysis process. The data that is associated with this analysis, and the results of the risk assessment process, will be captured utilizing a database management tool. The following section describes the nodal breakdown or the infrastructure segmentation process that will be employed during the risk assessment implementation phase of the project and the organizational structure and hierarchy of the database tool that will be used for data management.

The use of a nodal analysis is very common practice for conducting risk assessments and for maintaining organization in the execution and documentation of a study of such large magnitude. The nodal approach is a sequential and methodical way of examining all potential initiating events or failures that can occur anywhere in the overall "system of systems." Application of this nodal approach addresses the initiating events or failures that occur within a singular node while considering the consequences or impacts of such an event on a system-wide scale. This is commonly referred to in terms of assessing "Global Consequences." The risk assessment will include the documentation of all of the credible consequences from a single node initiating event as they cascade through the entire scope of the oil and gas infrastructure, considering the consequences in both the upstream and downstream affected nodes. For example, if an oil processing facility system failure is identified that would cause a complete TAPS shutdown, the cause would be associated and documented within the processing facility node being considered, but ultimately the reliability consequence would be documented and categorized as a loss of all North Slope production for the period of the associated TAPS shutdown. This concept of "consider local causes, but account for global consequences" is a commonly implemented approach for a wide variety of risk assessment projects.

5.1 Definitions

The following definitions describe the various parts of the overall infrastructure and provide a common set of terms for explaining the organizational structure of the data management for the infrastructure facility and component breakdown, or nodal analysis. Some of the terms have been customized and are described in the context of how they will be used in this project. An effort has been made to use the same terminology and definitions as those used by the Petroleum Systems Integrity Office and the Alaska Department of Environmental Conservation to describe Alaska oil and gas infrastructure and maintain alignment with regulatory definitions when available.[26,27] However, this is not intended to be a comprehensive list of infrastructure and component terms; rather it is a list of the terms which are anticipated to be commonly used during the risk assessment. Furthermore, the definitions presented were developed to create a common language for the project and are therefore project specific. Definitions are not intended to follow any single agency's set of regulatory definitions.

5.1.1 Infrastructure Facility Definitions

Term	Definition
Infrastructure Region	One of the three overall geographic zones in the state that contain oil and gas facilities (North Slope, Cook Inlet Basin and TAPS Corridor) and are being considered as part of the risk assessment scope.
Operating Area/Unit	An oil and gas lease unit or lease boundary area located within the North Slope or Cook Inlet Infrastructure Regions which contains oil and gas field development or production activities, and the facilities that exist to support those activities.
Facility	The structures and equipment located in the Alaska Oil and Gas Infrastructure Regions that are used to transport or process produced fluids and which are being considered in this project. Facilities include the oil and gas production and processing equipment in the North Slope and Cook Inlet Regions and the pump stations and pipeline equipment associated with TAPS.
Components	The major pieces of equipment or systems that perform a certain function or process. A component is the smallest piece, or segment, that will be considered as a single node for analysis purposes. A facility is comprised of components/systems that are grouped together and support the production and processing of oil and gas from one location.
Node	An individual segment or component of an individual facility in a specific location and environment that will be used for purposes of analysis.

5.1.2 Specific Component Definitions

Term	Definition
Wells, Well Site or Well Bay	The group of wells (production or service wells) associated with a certain facility. The term *well bay* is used for offshore platforms. Other names for a group of wells located together at a single onshore site are *wellpad* or *drillsite*. The wells or well site component includes the well bores and associated equipment and piping/lines which carry flow from the wellhead through the downstream onsite piping systems and equipment (manifold piping, headers, testing equipment, etc.)
Gathering Lines	A pipeline that transports gas or oil from a production facility (such as a central processing facility like a gathering center or flow station on the North Slope) to a transmission line.
Flowline	The production fluids from individual wells that are located at the well sites are diverted to flowlines (pipelines). Flowlines begin at the wellpad or marine structure outlet and transports the produced fluids through the field to central processing facilities for separation and further treatment. Reversely, flowlines also transport produced water back from processing facilities to well sites for re-injection. *(Multi-phase and produced water lines are considered flowlines)*
Transmission Line	A pipeline, other than a gathering line or common carrier pipeline, that transports oil or gas from a gathering line or central processing facility to a downstream facility or main pipeline system where custody transfer occurs. Transmission lines from North Slope Region facilities are commonly called "transit lines."
Common Carrier Pipeline	A pipeline that assumes the status of and will perform all of its functions undertaken under the lease as a common carrier and will accept, convey, and transport without discrimination crude oil or natural gas delivered to it for transportation from fields in the vicinity of the pipeline. It will accept, convey, and transport crude oil or natural gas without unjust or unreasonable discrimination in favor of one producer or person. These pipelines are normally DOT regulated pipelines and systems, which are operated by a separate pipeline operating organization, other than a single owner/operator of the production facilities in the region. Usually, these pipeline companies are entities that are owned and operated by several of the owners/operators of the production facilities in the region.
Other Associated Pipelines	All other pipelines within infrastructure boundaries that are not described above.

Note: Definitions presented were developed to create a common language for the project and are therefore project specific. Definitions are not intended to follow any single agency's set of regulatory definitions.

5.2 Database Tool

A Microsoft Access® type data platform will be used to capture the information for the risk assessment. The database will be developed as a stand-alone tool, or will be customized with appropriate data fields from existing risk assessment software. The data hierarchy for the infrastructure nodal breakdown is described below for each infrastructure region.

During the analysis process, hundreds of scenarios will be documented to address both the operational and natural hazards that are applicable to each piece of the infrastructure. The data used to perform the analysis and the results will be managed and maintained in the project database.

During the preliminary screening process that is described in Section 6 of this report, worst case events will be postulated for each node. The consequences of each event will be determined and recorded on the appropriate consequence scales for each of the three consequence classes (safety, environment and reliability). Only those nodes for events resulting in significant consequences (i.e., usually greater than Category 1) will be flagged and carried forward for further study.

The more detailed operational and natural hazard risk assessment processes, (described in Sections 7 and 8 respectively) will include the development of likelihood (i.e., frequency) and consequence estimates for each scenario analyzed. The combination of those numbers will result in the actual risk estimate for the scenario. The detailed risk assessment data will be managed in the database for presentation of results of the risk assessment (described in Section 9). Figure 5-2 shows how an example scenario would be represented in the risk assessment database. The left window in the figure depicts how the infrastructure is organized in the underlying database, while the window on the right shows "typical" scenario details and format.

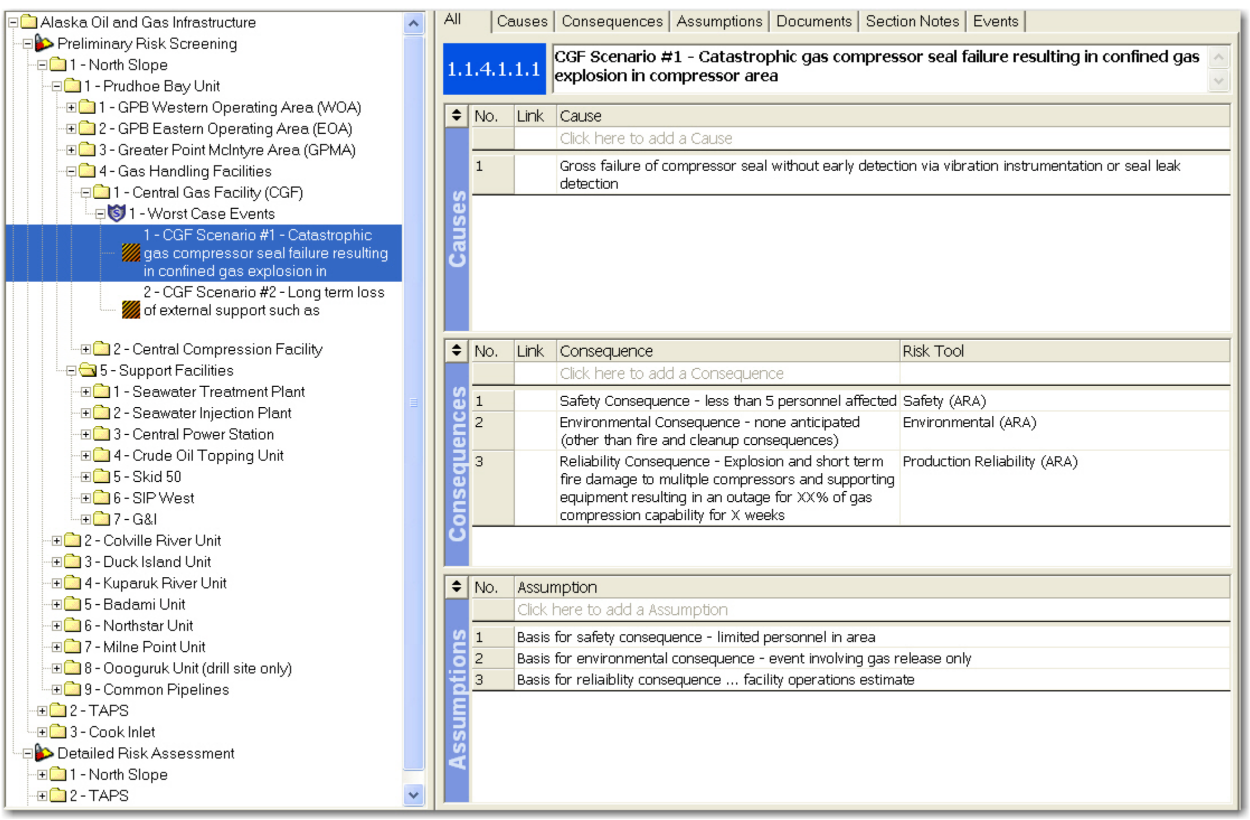

Figure 5-2 Risk Assessment Database Example

5.3 Infrastructure Segmentation Process/Nodal Breakdown

5.3.1 North Slope Infrastructure Region

The North Slope Infrastructure region encompasses most of the operating areas or units on the North Slope of Alaska (Note: It does not include areas or units that were not producing as of July 1, 2008). Each operating area has at least one central oil and gas processing facility which receives the produced fluids from associated well sites in the area or unit. Some operating areas have multiple central processing facilities which process the fluids from different groups of wells within the area. For example, the Northstar Unit has a single central facility that receives production fluids from associated wells in that area while Greater Prudhoe Bay has six central processing facilities, each of which receives fluids from at least five wellpads. A pipeline network that crosses the region transports fluids from multiple facilities across fields.

5.3.1.1 Central Oil and Gas Processing Facilities

Three-phase production fluids are transported from the well site through flowlines and gathering lines throughout the field to the central processing facility. In some North Slope region operating areas, significant cross-country distances (miles) separate well sites from the nearest associated central processing facility. In other areas the wells are connected directly to the processing facility through minimal distances of piping. Each central processing facility separates multi-phase produced fluid stream into oil, gas and water streams. The major components or systems that are inside the central processing facilities include the equipment that is required to perform the oil separation, gas handling, and produced water treating functions. The three separate "product" streams (oil, water, and gas) flow from the central facility through a system of transmission pipelines to either sales (crude oil to the TAPS), or back to the well sites for reinjection into the reservoir for pressure maintenance and enhanced oil recovery (water and gas). Produced water may also be disposed of in disposal wells. Some gas may be sent on to downstream handling systems (gas handling facilities) for further processing and is ultimately reinjected into the gas cap for reservoir pressure maintenance.

5.3.1.2 Gas Handling Facilities

Gas that requires further processing is transported to the gas handling facilities (Central Gas Facility and Central Compressor Plant – CGF and CCP) for the Prudhoe Bay Unit on the North Slope. Gas that is not piped back to the well sites from the central facilities is sent through the gas handling facilities and used for artificial lift (gas lift) or gas injection. The major components of the CGF and the CCP are the systems and equipment that are required to perform the extraction of natural gas liquids (NGL) from the produced gas stream and increase the gas pressure to a sufficient level for reinjection back into the gas cap. In other operating areas on the North Slope, further gas handling (NGL extraction after separation and dehydration) and injection is achieved in the associated central processing facility, and those systems and equipment for additional gas processing or treatment are part of this facility.

5.3.1.3 Support Facilities

The central processing facilities on the North Slope may receive outside support for operations (fuel and power) from separate support facilities. Support facilities include seawater treatment and seawater injection plants, power stations (such as Prudhoe Bay's Central Power Station [CPS]), crude oil topping units, which refine crude oil to obtain fuel for daily operations, and grind and inject facilities, which are used to dispose of waste materials generated from downhole activities) and Skid 50, which blends NGLs and crude oil from the east and west production facilities in preparation for delivery to Pump Station 1. For other North Slope operating areas, the central facilities are self sufficient in that they receive no outside support from other facilities (i.e., they have their own utility systems and generate their own power and fuel onsite).

5.3.1.4 Pipelines

In addition to the overall set of facilities that comprise the North Slope region infrastructure, a number of common carrier pipelines transport fluids across the North Slope. These pipelines may not tie to any individual facility as an inlet (feed) or outlet (product) line. Instead, they may tie into the regional pipeline system network downstream of the facilities via a transmission line or gathering line. All common carrier pipelines in the region that transport fluids will also be considered in the risk assessment.

Figure 5-3 shows the North Slope infrastructure region facilities/pipelines to be studied.

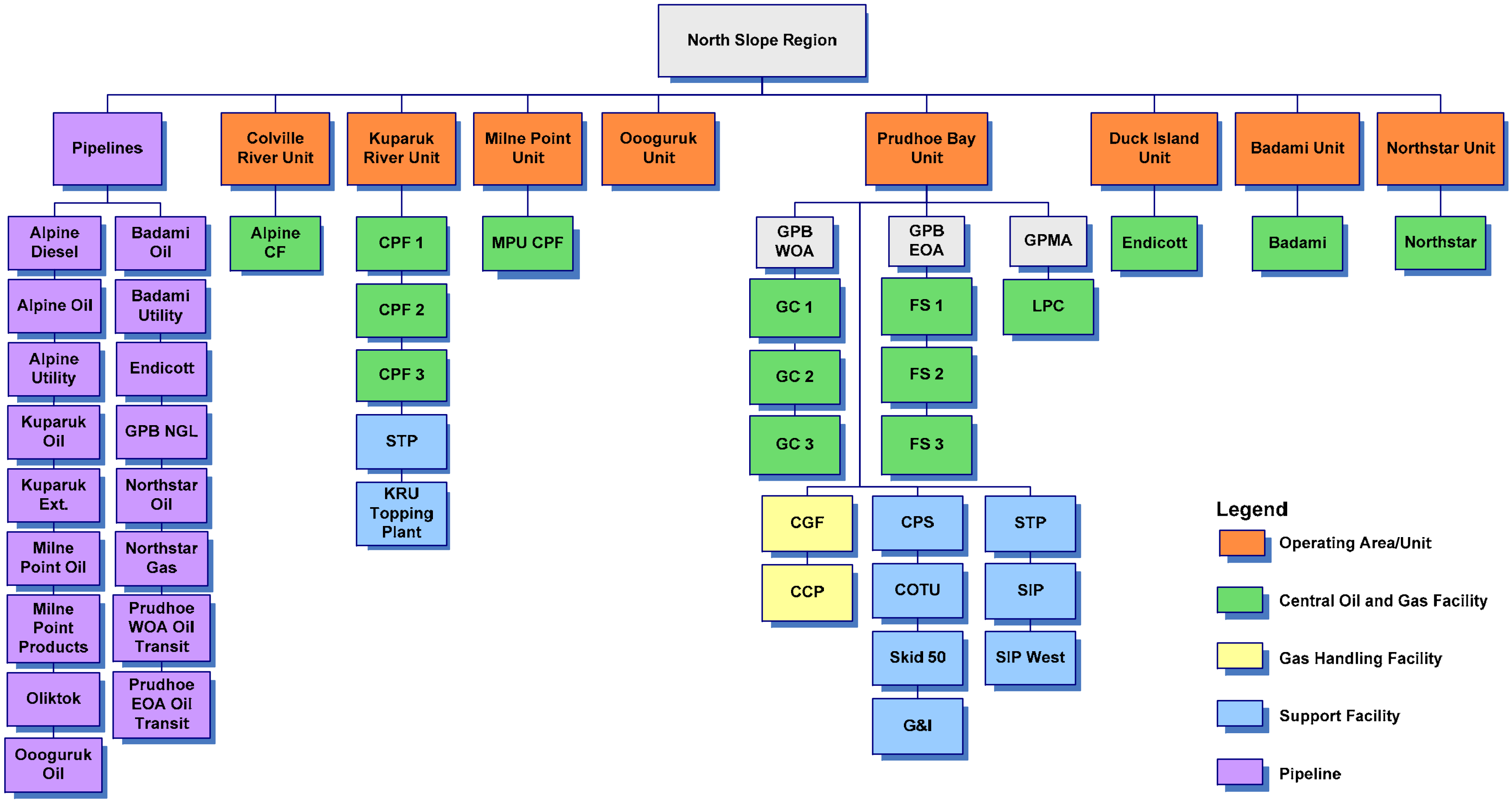

Figure 5-3 North Slope Region Facilities and Pipelines

Note: Refer to Table 4-1 for detailed information on North Slope infrastructure, including definitions of the acronyms used in this figure.

5.3.1.5 North Slope Infrastructure Nodal Breakdown

Each facility that makes up Alaska's Oil and Gas Infrastructure in the North Slope region can be categorized as one of the three different types of North Slope region facilities: *central oil and gas*, *gas handling*, and *support* facilities. Each facility to be considered in the risk assessment will be segmented into major components/systems for the analysis, based on the functions or processes of the individual facility type. The list of components/systems for each facility type shown in Figure 5-4 is intended to be a generic list of the kinds of systems and major equipment that make up the facility type, and will be made more specific as the internal facility systems and processes are better understood from data gathering and discussions with the facility owners/operators for verification of the data that is acquired.

When analyzing the inlet and outlet pipeline systems for each facility and common carrier pipelines, it is possible that additional pipeline component segmentation may be required for longer, cross-country pipelines which have specific isolatable pieces and may cover large distances. Pipelines may be routed through numerous environmentally sensitive areas, may run over many areas of varying geology and topography, and may be located above or below ground. Long pipelines will be divided into an appropriate number of nodes for the analysis based on specific location and consideration of these other factors.

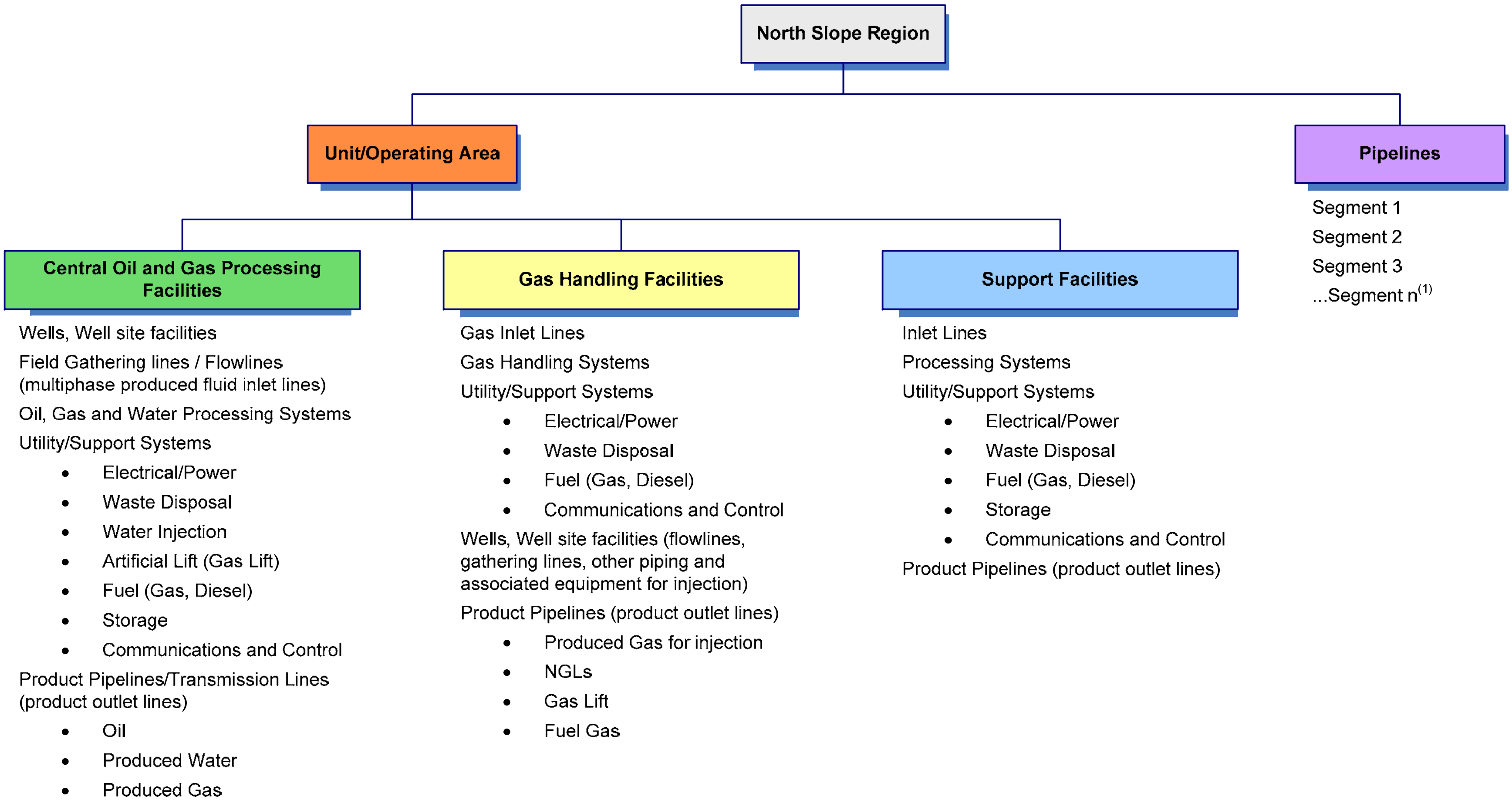

Figure 5-4 North Slope Infrastructure Nodal Breakdown

5.3.2 Cook Inlet Infrastructure Region

The Cook Inlet Infrastructure region encompasses numerous operating areas or units, both onshore and offshore, on the east and west sides of the Cook Inlet Basin in South-central Alaska. The offshore facilities consist of 16 oil and gas production platforms, 12 of which are currently in operation and 4 of which are in shut-in status (referred to as "lighthouse" mode). The production from these platforms is sent to onshore production/processing facilities, where the produced fluids are processed and separated into oil, gas and water streams. The oil and gas become product streams that are routed to sales and distribution points via oil and gas pipeline systems in the region. The produced water may be shipped back to the platform from an onshore production facility for reinjection, or is cleaned, treated and discharged as permitted into the Cook Inlet, either overboard from the platform or from the onshore facilities after further treatment.

Additional facilities in the Cook Inlet region serve as central facilities in support of oil and gas production and processing (gas and oil fields) which are located in onshore operating areas or units.

The typical facilities that make up the Cook Inlet region infrastructure are shown below in Figure 5-5. Each of the Cook Inlet region facilities will be considered and analyzed as one of these facility types. Each facility that is considered within the scope of the review will be segmented according to the major components that make up the facility.

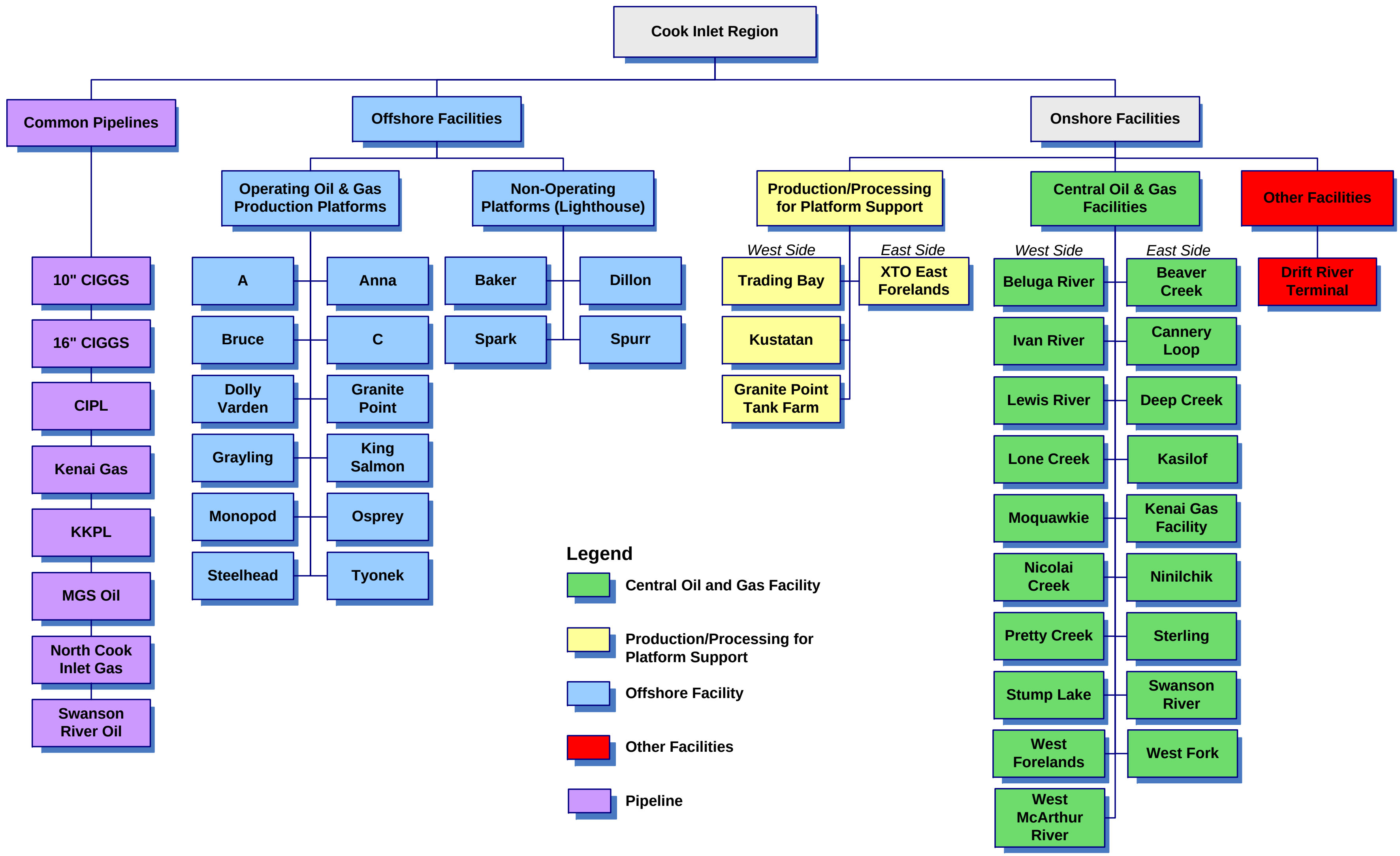

Figure 5-5 Cook Inlet Facilities and Pipelines

Note: Refer to Table 4-3 for detailed information on Cook Inlet infrastructure, including definitions of the acronyms used in this figure.

5.3.2.1 Offshore Oil and Gas Production Platforms

The oil and gas platforms that are located in the Cook Inlet region consist of a set of wells that produce fluids from a given offshore operating area or unit and the major equipment and systems that allow for at least partial processing of the produced fluids (some oil, gas and water separation) on board. The production fluids (usually multiphase) are routed to an associated onshore production/processing facility via subsea pipelines where further separation and treatment normally takes place.

5.3.2.2 Onshore Production/Processing Facilities (Platform Support)

There are production/processing centers that are located on both the east and west sides of the Cook Inlet which support the production of oil and gas that comes from the offshore platforms. Most of these production/processing centers receive production fluids from more than one platform, depending on the ownership of the platforms and the processing requirements that each individual platform owner/operator has for their fluid streams.

The onshore production/processing centers receive the partially processed fluids from the offshore production platforms. These facilities are comprised of the systems and major equipment that are required to perform the final separation and treatment of the oil, gas and water that they receive, into sales product or disposal streams. The final gas and oil product streams from the production/processing centers are either routed to another production/processing center for distribution/transport and sales, sent into a pipeline and/or gathering system for distribution (gas), or into a crude oil pipeline system for routing to a sales point or marine transport (from the Drift River Terminal Facility). The treated water streams from the production/processing centers are discharged into the Cook Inlet as permitted or disposed of via onsite injection/disposal wells.

5.3.2.3 Onshore Central Oil and Gas Processing Facilities

Numerous onshore operating areas or units in the Cook Inlet region have been developed for oil and gas production. These areas consist of a set of wells and the facilities which support the production and processing of the fluids that come from those wells. In some instances these fields have been producing for decades and have over 40 wells on site, which are supported by an extensive number of facilities that are part of the oil and gas infrastructure. In some of the newer operating areas, where development has taken place in the last few years, only a few producing wells have been brought online to date, and the existing processing facilities are minimal. In all cases where producing wells exist, there are some “facilities” in place with equipment and systems for processing and delivering the produced fluids for sales.

5.3.2.4 Terminal Facility

The Drift River Terminal is also in the scope of this project for the Cook Inlet region. This terminal supports storage and transport of crude oil sales product from the Cook Inlet region, and consists of crude oil storage capacity (tankage) and marine loading facilities which load tankers berthed at the offshore Christy Lee loading platform.

5.3.2.5 Pipelines

The Cook Inlet region has a number of common carrier pipeline systems that will be considered in the analysis including the Cook Inlet Gas Gathering System (CIGGS), the Cook Inlet Pipeline (CIPL), Kenai Oil Pipeline, Kenai Gas Pipeline, Kenai-Ninilchik Pipeline (KNPL), Kenai-Kachemak Pipeline (KKPL), North Cook Inlet Gas Pipeline, and the North Cook Inlet Oil Pipeline.

5.3.2.6 Cook Inlet Infrastructure Nodal Breakdown

For purposes of dividing the offshore oil and gas production platforms into smaller components and systems, these facilities can be considered to be similar to the central oil and gas processing facility that is typical on the North Slope. The platforms service a set of wells and contain the partial processing equipment necessary to perform at least some oil, gas and water separation functions. Products are routed via pipeline to the onshore production/processing centers, which are considered similar in function to the central oil and gas processing facilities on the North Slope. The platforms and the onshore production/processing centers together will contain the major equipment and systems that are required to separate the oil, gas and water streams that come from the wellheads on the platforms into product streams. Special consideration will be given to the structure of the offshore production platforms as an individual component or node to be assessed as part of the review.

The onshore central oil and gas processing facilities in the Cook Inlet region will be considered in a similar fashion to the central processing facilities on the North Slope. These facilities include similar systems and components for produced fluid (oil, gas and water) processing.

The Cook Inlet region facilities will be segmented into components and systems for the typical facilities based on Figure 5-6. An understanding of the major equipment in a facility and the processes that take place at the facility, based on data gathering and discussions with owners and operators, will lead to a more specific development of the nodal breakdown for each facility.

When analyzing the inlet and outlet pipeline systems for each of the onshore and offshore facilities in the region and the common carrier pipeline systems, there may be additional pipeline segmentation that is required for longer, subsea or cross-country pipelines which have specific isolatable pieces and may cover large distances. Onshore pipelines may be routed through numerous environmentally sensitive areas, may run over many areas of varying geology and topography, and may be located above or below ground. Subsea pipeline systems may be buried or sitting on the sea floor.

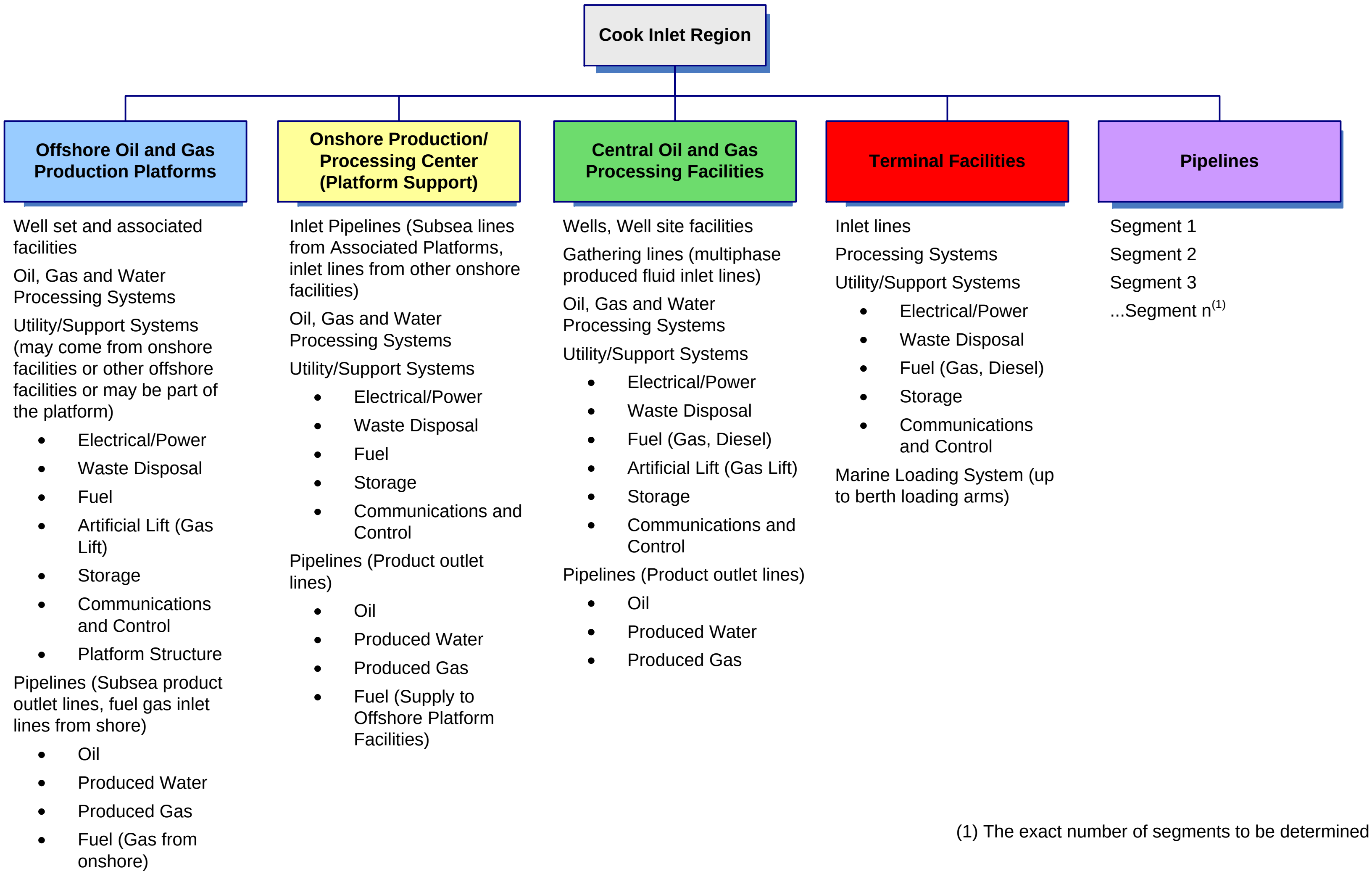

Figure 5-6 Cook Inlet Infrastructure Nodal Breakdown

5.3.3 Trans Alaska Pipeline System (TAPS) Infrastructure

TAPS infrastructure includes the pump station facilities and the pipeline segments that run between those operating pump station facilities, as well as the Valdez Marine Terminal. The components of TAPS infrastructure are shown below in Figure 5-7:

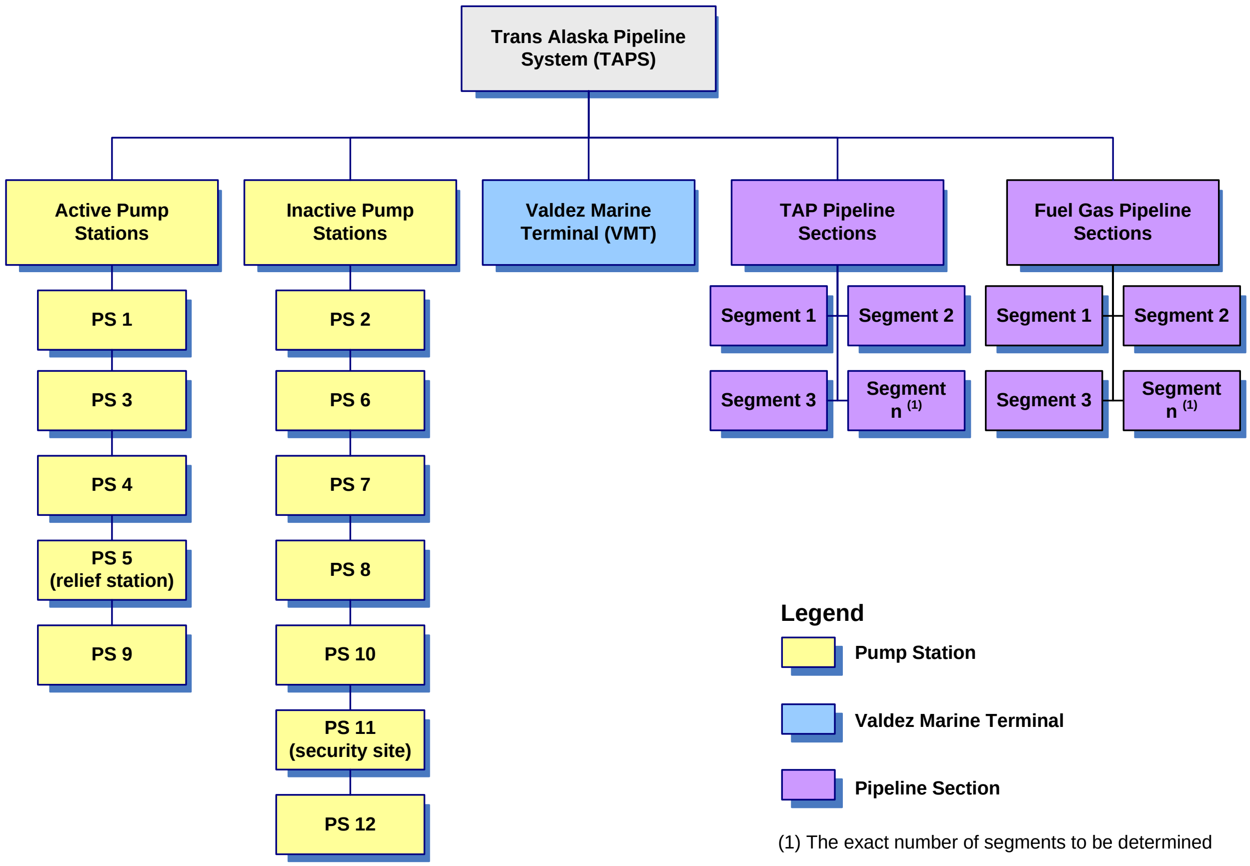

Figure 5-7 TAPS Infrastructure Components

5.3.3.1 Pump Stations

The original design of TAPS called for 12 pump stations equipped with 4 pumps each.[28] PS 11 was never built and exists as a security site only.[21] The pump stations as originally designed included valves, piping, pumps, tanks, and control equipment designed to relieve excessive pressures on the pipeline when the pipeline or a pump station shuts down.

Currently, four operating pump stations (PS 1, 3, 4, and 9) propel oil through the pipeline.[21,29] One additional pump station (PS 5 on the southern slope of the Brooks Range) operates as a pressure relief station (when required) and never had pumps installed. As a result of the decline in throughput that has been ongoing since the beginning of the 1990s, five other pump stations (2, 6, 7, 8, 10, and 12) have been placed on standby.[21,29] More recently, pumps at two of the standby pump stations (PS 2 and PS 12) have been disconnected from the pipeline entirely.

PS 1 is connected to Prudhoe Bay's central power grid and uses fuel gas from the North Slope fields. Fuel gas from the North Slope fields is also used to power and operate PS 3 and PS 4. The fuel gas is delivered to PS 3 and PS 4 through a 149-mile fuel gas line that originates at PS 1 and varies in diameter from 10 inches to 8 inches. The pump stations located farther south are powered by turbines that use liquid fuel, except for PS 9, which purchases commercial power from the nearby Golden Valley Electric Association (GVEA). PS 8 and 12, which are not active pump stations, have also purchased commercially generated power from local providers in the past.[24]

5.3.3.2 Trans Alaska Pipeline (TAPS) Sections

The Trans Alaska Pipeline is 800.3 miles (1,288 kilometers) long, with an outer diameter of 48 inches. The total area covered by the pipeline system is approximately 16.3 square miles. The pipeline crosses three major mountain passes: the Brooks Range, the Alaska Range, and the Chugach Range. Its highest elevation is at Atigun Pass (4,739 feet). It also crosses Isabel Pass (3,420 feet) and Thompson Pass (2,812 feet). The pipeline crosses 34 major rivers and nearly 500 other smaller rivers and streams.

The pipeline is elevated aboveground for 420 miles and buried for the other 380 miles. To prevent thawing of permafrost, the 420 miles of aboveground pipeline is mounted on approximately 78,000 vertical support members (VSMs) located about every 60 feet. Some buried sections of the pipeline are insulated or refrigerated and insulated to prevent thawing of the permafrost due to heat from the pipeline.

Valves are strategically placed along the pipeline to isolate sections of the pipeline and to minimize the size of potential spills in the event of a pipe rupture. There are 177 valves total, with 81 check valves, 71 gate valves, 24 block valves, and 1 ball valve. Most of the gate or ball valves can be controlled from the Operations Control Center (OCC) or from the pump stations. Valves can be operated manually for maintenance of the line or for spill isolation, if necessary.[30]

5.3.3.3 Fuel Gas Pipeline

The fuel gas line carries natural gas from North Slope fields to fuel pump stations north of the Brooks Range. In general, the fuel gas line parallels the mainline crude oil pipeline from Prudhoe Bay to PS4. (Stations south of the Brooks Range are fueled by liquid turbine fuel.)

5.3.3.4 Valdez Marine Terminal

The VMT, at the southern end of the TAPS, is where crude oil is loaded onto tankers for transport to market. The VMT site encompasses over 1,000 acres on the southern shore of Port Valdez. The VMT has facilities for crude oil metering, storage, transfer, and loading. Incoming crude oil is metered and sent either to one of fifteen 510,000 bbl storage tanks currently in service or directly to a tanker. The VMT has berths that can accommodate mooring of three tankers at once, although only two of the berths (Berth 4 and 5) have vapor control systems and are used for loading tankers. Berth 3 is used as a lay berth for tankers, and Berth 1 is out of service.

To reduce air emissions, vapor recovery systems collect crude oil vapors from the crude oil storage tanks and the Ballast Water Treatment (BWT) facility as well as the vapors that are vented from tankers as they are loaded with crude oil at the berths. Before transfer to a tanker begins, crews place an oil spill containment boom around the entire berth and the tanker. The BWT facility treats the ballast water that is collected from the tankers as the oil is loaded in order to recover the oil from the ballast water.

The VMT was designed to provide the storage capacity in TAPS to allow production on the North Slope to operate without impact from delays in the marine transportation system. The VMT currently has storage facilities with a working inventory capacity of 6.2 million bbl of crude oil and a total active volume of 7.3 million bbl.[24,21]

5.3.3.5 TAPS Infrastructure Nodal Breakdown

For purposes of dividing TAPS infrastructure into manageable nodes for analysis, the pump stations will be considered as one type of facility and the Valdez Marine Terminal will be considered as a second facility type (which will be treated similarly to the Cook Inlet region terminal facility type).

TAPS pipeline segments that are located between the pump stations can be tens or even hundreds of miles long and can cover many geographical areas with varied topography. These pipeline segments can cross sensitive environmental areas and can be below or above ground and may have refrigerated segments to protect the sensitive permafrost layer from thawing. The pipeline segments will be divided into nodes, as appropriate for the project, based on numerous factors which could include the ability to isolate the section, anticipated spill response measures for the area, the type of line (above or below ground), natural hazards applicability to the region or local area, etc. If appropriate, the TAPS pipeline segmentation process may follow the node breakdown process that was employed in previous pipeline assessments where the priority for consideration was the environmental sensitivity of the area. These studies may be available for use and include the TAPS Right of Way Renewal EIS and the DOT Integrity Management High Consequence Area Risk Assessment.

The component or nodal breakdown for TAPS pump stations, the Valdez Marine Terminal, and the pipeline segments are outlined in Figure 5-8.

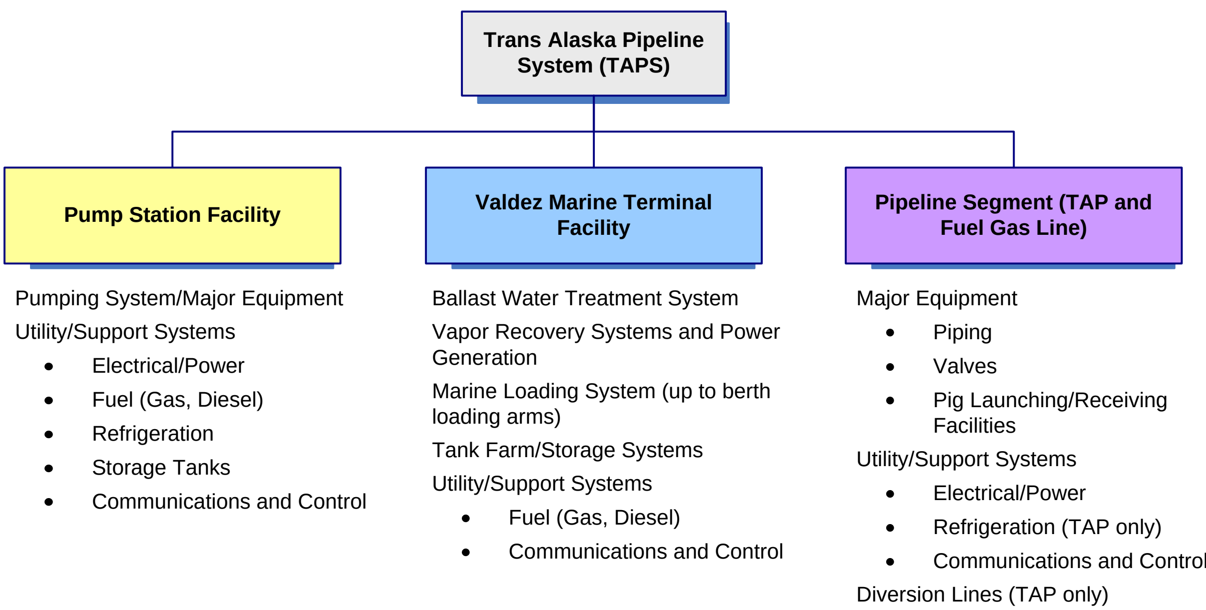

Figure 5-8 TAPS Infrastructure Nodal Breakdown

6 PRELIMINARY INFRASTRUCTURE RISK SCREENING

The risk assessment implementation and analysis efforts (Phase 2 and 3 of the ARA Project) will focus on areas that have the greatest potential to have the highest risks of interest to the State.

Risk assessment involves three steps:

1. Defining what can go wrong (i.e., identifying an undesirable event)

2. Estimating the frequency for such an event to occur

3. Calculating the possible consequences associated with the event

To help focus the risk assessment on those infrastructure components that could present potentially high risk events, individual infrastructure nodes will first be screened to identify those areas that could potentially experience events resulting in consequences of interest (i.e., significant consequences). For example, if consequence screening determines that severe adverse events in a specific portion of the Alaska oil and gas production infrastructure cannot cause a significant safety, environmental, or reliability consequence, resources will not be spent to analyze and estimate the frequency of those events.

6.1 Consequence-Based Preliminary Screening Approach

The infrastructure nodes will be defined for screening and further analysis as discussed in Section 5. For each node defined, reasonable worst case scenarios and resultant worst case consequences that could occur due to those undesirable events occurring in the node will be postulated using the HazID technique described in Section 3.2.1. A comparison of worst case consequences will be made to the screening threshold criteria for each consequence class to be considered for the scope of the review (safety, environment and reliability). Only those infrastructure nodes that result in potential events with consequences that exceed the screening threshold for a specific consequence class will be examined in the detailed risk assessment that will be performed during later implementation activities.

Figure 6-1 graphically displays the preliminary screening process steps.

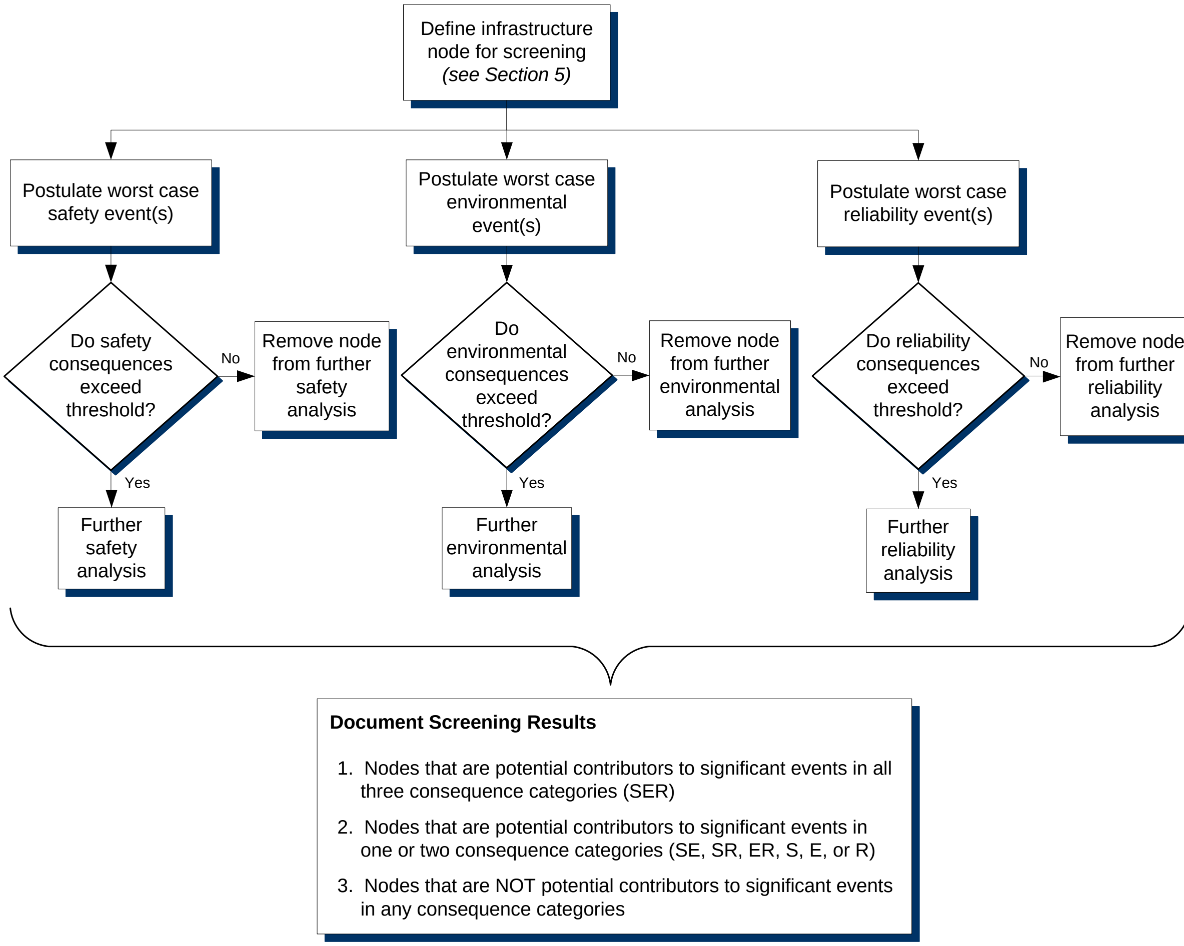

Figure 6-1 Preliminary Screening Process Diagram

6.1.1 Screening by Consequence Type

The preliminary consequence screening of infrastructure nodes will be applied independently for each class of consequence. The development of worst case scenarios for each of the three types of consequences to be considered is provided in subsequent subsections of this description. Considering the potential impacts of the worst case scenarios, it will be determined whether the specific event consequences exceed the screening threshold of the upper limit of Category 1 on the consequence scale as defined for each consequence class. If the threshold is exceeded, the project database will be updated to indicate that the node will require further analysis in the more detailed risk assessment implementation. If worst case consequences for the node do not exceed the screening threshold criteria, independent events that affect the node will not be considered in subsequent analyses for that specific consequence classification.

For example, since each of the three consequence classes will be considered independently during the screening analysis, a node might not meet the safety consequence or environmental consequence Category 1 criteria, but may exceed the reliability consequence Category 1 criteria. In that case, further detailed analysis of the node would need to address only reliability effects. This example might hold true for an infrastructure node in an area that meets the following criteria:

- Few workers or members of the public are located nearby
- The area is within secondary containment or a prepared surface

– A combined crude production stream flows at a relatively high rate

The preliminary screening will continue for each consequence class for each node within the scope of the risk assessment until the nodes have been examined for each consequence class.

6.2 Safety Consequence Screening

Safety consequences that are of interest in this risk assessment include potential safety impacts to both infrastructure workers and to members of the public. Table 6-1 presents the safety consequence categories defined for the risk assessment. The potential for safety impacts will address both occupational and public safety as defined by 1) Occupational - workers involved in infrastructure operations, and 2) Public - people in residential areas or at industrial/commercial properties located near an infrastructure component. It should be noted that safety impacts to be considered specifically exclude the analysis of impacts to members of the public that are simply passing by an infrastructure item when an event occurs (defined as being in the wrong place at the wrong time). This type of random interaction is considered unlikely to be significant (i.e., would not occur frequently and/or would not involve large numbers of people).

For each consequence type, the infrastructure will be divided into physical areas or nodes for analysis. In the preliminary screening for determining the worst case scenarios in terms of safety impacts, a large scale loss of containment from the node, due to a large leak or rupture will be postulated, and will model the worst case resultant safety consequences if:

1. The product stream in the node is a hydrocarbon that has the potential to ignite and escalate to a fire and/or explosion event; and

2. There are workers or members of the public which have the potential to be in the direct vicinity of the area of the release/fire or explosion event. *(Analysis of safety risks will focus on scenarios involving the ignition of uncontained hydrocarbons. Toxic impacts and chronic health effects will not be modeled as part of this assessment)*

If these two conditions are not present in the node being considered, no worst case safety scenarios will be developed and the node will be excluded from further analysis for safety consequences.

If the two conditions above are present in the node then worst case scenarios for hydrocarbon releases from the infrastructure components being considered will be developed which have the potential to result in fires and/or explosions based on the product stream and degree of confinement at the location. Basic hydrocarbon release consequence models for fire and explosion such as Vapor Cloud Explosion and Jet Fire modeling will be used to estimate the distances to which severe injury and fatalities could be experienced by workers at the facilities and by the nearby public.

Detailed technical approaches to hydrocarbon release models are included in Appendix D and will be like those described in Section 7.2 for the operational hazards risk assessment. For preliminary screening purposes, the model inputs will be based on simplifying assumptions like 1) large leak/rupture release rates expected (e.g., 20% to 100% of normal process flow), 2) worst case meteorological conditions, 3) delayed ignition where explosions are possible, and 4) other assumptions that ensure conservatism appropriate for screening. Using the results of the screening consequence analyses and the information regarding location of onsite and offsite populations, the reasonable worst case safety consequences (in terms of number of worker and public fatalities) will be assessed for events in each area/node of the infrastructure. If the consequences do not exceed Category 1 levels listed in Table 6-1, that section of the infrastructure will not be further considered in the risk assessment for safety risks.

Table 6-1 Safety Consequence Categories for Preliminary Screening

Category	Occupational Safety Impact (Number of Potential Fatalities)	Public Safety Impact (Number of Potential Fatalities)
5	> 100	>10
4	51 to 100	6 to 10
3	11 to 50	2 to 5
2	5 to 10	1
1	< 5	No public safety impact

Note: *The safety categories used in* Table 6-1 *are not intended to imply that workers in the oil and gas production business are less important than members of the public, nor does it imply that events that could potentially injure less than five workers are not important. The categories that have been defined above 1) reflect the purpose of this risk assessment as chartered by the State; i.e., to examine catastrophic level events that are potentially high risk which could result in severe or significant consequences, and 2) recognize the large quantity of resources that are already dedicated to protecting the workers and members of the public from accidents that involve the oil and gas infrastructure. Less severe safety threats to workers and the public are already managed by regulations and extensive corporate safety/risk management programs.*

6.3 Environmental Consequence Screening

Environmental consequences of interest in this risk assessment include only loss of containment/ spill events of a hydrocarbon or seawater stream that have the potential to create adverse effects on the external environment. *(The focus of this project will be on hydrocarbons and seawater only, and will not include assessment of other types of hazardous substances)*

Numerous contributing factors determine the severity of the environmental impacts of a hydrocarbon or seawater liquid release to the external environment. The size of a potential spill is the initial factor which will be used to determine whether or not the impacts may be significant enough to be included in this risk assessment.

For each consequence type, the infrastructure will be divided into physical areas or nodes for analysis. In the preliminary screening for determining the worst case scenarios in terms of environmental impacts, a large scale loss of containment from the node, due to a large leak or rupture will be postulated, and will determine whether or not the worst case resultant environmental consequences have a significant impact by determining if:

1. The product stream in the node is seawater or a liquid of some hydrocarbon content; and
2. The liquid release event is not contained in secondary containment or on a prepared surface such as a gravel pad.

Note: *The risk assessment will examine some events (primarily severe natural hazards like major earthquakes) that could cause storage tank failure and failure of secondary containment. For example, such an event may be appropriate to consider for the Valdez Marine Terminal, but would be expected to be relatively rare due to severity of the seismic event it would require. However, simultaneous, but independent failures of a storage tank and the secondary containment around it will not be assessed for all storage tanks. Such combinations of independent failures: 1) are expected to be low frequency contributors because both failures must exist simultaneously, and 2) would have smaller consequences than releases involving severe failure of secondary containment because they would generally involve smaller release paths (e.g., through a dike drain valve left open or through an unrecognized leakage pathway in a dike).*

If these two conditions are not present in the node being considered, no worst case environmental scenarios will be developed and the node will be excluded from further analysis for environmental consequences.

If the two conditions above are present in the node, a worst case scenario for a loss of containment/spill from the infrastructure components being considered will be developed to determine the potential spill volume which could be released to the external environment. Spill volumes will be calculated by assuming worst case rupture scenarios from lines, vessels or other major equipment within a node, which can result in a release of fluids. The volume of the release will be estimated based on the normal production flow rate through the node and the estimated time that it takes for that flow rate to shut off due to automated engineered detection/controls or via manual shut-off from visual detection. A Nodal Production Diagram will be developed for use in this project to help determine potential release volumes and inventories; the Nodal Production Diagram will depict normal production flow rates for each type of fluid (oil, gas, water and mixed phase) that is present in each node. Information from industry regarding leak detection systems, automatic shut-off controls, and normal operator rounds will also be used to determine the amount of time that the worst-case flow volume would be expected to occur, or engineering judgment will be applied to assess these scenarios.

Typical spill volume categories and ranges have been derived from a review of regulatory spill reporting requirements, contingency planning thresholds, and typical industry risk assessment spill guidelines. A summary of environmental discharge thresholds has been provided in Appendix B. This information has been used to develop the following spill volume categories in Table 6-2, which will be used as the basis for the preliminary screening criteria for the environmental impacts assessment.

Data that is available from the North Slope Oil Spill Summary[27] indicates that the top ten spills on the North Slope for the nine-year period between January 1, 1996 and December 31, 2004 ranged in volume from 24 to 900 barrels (1,000 to 38,000 gallons) of fluid. Therefore, for purposes of this project, a spill of significance will be defined as a spill which would fall into a similar range to those of the top ten spill events on the North Slope. The following definitions of spills of significance have been developed for this risk assessment.

Table 6-2 Spill Categories for Preliminary Screening

Category	Volume (bbls of fluid)
4	> 10,000
3	1,001 to 10,000
2	10 to 1,000
1	< 10

Only those scenarios from the nodes which result in worst case spill volumes that exceed the Category 1 threshold of 10 barrels in Table 6-2 will be further considered in the detailed environmental risk analysis for spill events. Worst case scenario descriptions and calculated spill volumes for the nodes considered in the preliminary environmental screening process will be recorded in the risk assessment database.

The detailed environmental risk analysis will be completed using an Environmental Scoring Model which is outlined in Section 7.3 of the operational hazards assessment. In order to fully assess the risks of each type of potential spill scenario that could be postulated for the entire infrastructure, a quantitative scoring approach has been developed which assigns a numbered value (or index) for each of the various individual contributing factors for spill risk. This model will be employed in performing a detailed risk assessment for those nodes which have potential significant environmental impacts based on the preliminary environmental screening efforts.

6.4 Reliability Consequence Screening

Reliability consequences are of interest in this risk assessment, where reliability is quantified in unexpected loss of oil measured in barrels (bbls) and gas production in barrels of oil equivalent (BOE) (based on the approximate energy released by burning one barrel of crude oil, which is equal to 5.8×10^6 BTU). In preliminary risk screening, for each node in the oil and gas infrastructure, the reasonable worst case events that could result in loss of production will be assessed. The worst case production impact that could occur (i.e., the magnitude of the loss of oil production or transport and the duration of that loss) will be estimated. Worst case release events will be postulated for loss of production from each node, based on similar worst case events that are proposed for the spill volume assessment that will be examined for environmental consequence screening (described in the above section).

The production loss for each node will then be assigned to one of the categories in Table 6-3. If the production loss consequences do not exceed Category 1 from the Table 6-3 screening criteria, that node of the infrastructure will not be further examined for the reliability risk assessment. If the production loss exceeds the Category 1 level from Table 6-3 for preliminary screening, the node will be examined in more detail in the continuing risk assessment activities.

Table 6-3 presents the consequence categories developed for those production losses that could be considered significant in terms of impacts to state revenue. The categories were developed in conjunction with DOR personnel to include a reasonable range of production interruptions with the potential to significantly impact state budget.

Table 6-3 Reliability Consequence Levels for Preliminary Risk Screening

Category	Category Production Loss Boundaries	Explanation (see Note)
3	>42,000,000 bbls	Corresponds to about a two month full outage for TAPS
2	4,200,000 to 42,000,000 bbls	Corresponds to an outage range which includes an approximate 30 day outage for TAPS or a two week outage for a production source that is half of the TAPS throughput
1	<4,200,000 bbls	Corresponds to less than a week outage for TAPS or a 60 day outage for a production source that is 10% of the TAPS throughput.

Note: Outages assume 700,000 barrels per day TAPS throughput

The reliability model presented above will be used to estimate losses associated with unplanned shutdowns due to events identified during the risk assessment. Measuring loss in barrels provides a flexible model that can be used by the State to determine revenue impacts to the state budget in consideration of varying oil prices and tax structures, as well as the specific budget and priorities of the administration at a given point in time.

Potential impacts to state budget can be measured by the State by converting the loss of production in barrels associated with a potential event to dollars. This can be accomplished using the DOR State Revenue Forecast model, which takes into account the price of oil per barrel and the associated royalty and tax structure. It should be noted that calculating revenue losses in this way considers royalty and tax revenue losses only, and does not consider other damages to the State.

Two examples demonstrating how the results of this model can be used to predict impacts to state revenue are presented below. These are hypothetical examples only and are intended to demonstrate how different scenarios could be used by the State to predict potential impacts to state revenue streams.

The first example uses the State's latest fiscal year 2010 oil forecast of $58 per barrel of oil, with associated State net revenue (royalties and taxes only) of approximately $11 per barrel. Assuming a 30 day outage of a North Slope Central Processing facility with a hypothetical production rate of 70,000 barrels per day (approximately 10% of overall TAPS throughput), associated losses would fall into the lowest category of the model (Category 1), as the impact to state revenue, would be approximately $23,100,000. Conversely, in a higher oil price environment, such as when North Slope crude prices are around $100 per barrel, the associated state net revenue (royalties and taxes only) is approximately $36 per barrel. In this scenario the associated loss for the same interruption would equate to approximately $75,600,000.

Another useful example is a potential interruption of the entire TAPS flow for an extended time, such as that described in the highest consequence category above (Category 3). Using the same $58 per barrel price assumption described in the first example, a production outage of TAPS for 90 days would equate to a $693,000,000 loss to the State. At $100 per barrel pricing and associated $36 per barrel state net revenue, this same outage would equal $2,268,000,000.

The State can use this type of information to assess potential impacts to the state budget and funding levels that are required for planned programs. For instance, in the examples described above, a

$23,100,000 loss may be deemed manageable by the State if it does not necessarily threaten critical or core state services and would only impact optional services such as additional investment in programs to increase cultural or entertainment activities, recreational activities, or would eliminate discretionary spending and cause deferral of optional capital projects, upgrades to existing infrastructure, or services.

Larger production interruptions such as that described in the second example above could similarly be converted to state revenue losses reflecting more severe impacts. For example, an outage of TAPS for an extended duration, as described above may be deemed catastrophic to the State if that interruption could have a dramatic impact on the State's ability to fund and provide basic or essential state services (e.g., law enforcement, fire protection, public health services, education support, welfare programs, and basic infrastructure safety programs).

Evaluations relating dollars of revenue lost to impacts on state budgets and programs such as those hypothetical events discussed above, are most appropriately conducted by the state DOR and are part of the risk management process that will follow this assessment. This will allow for the ability of the State to assess such budget impacts into the future using real time information related to oil prices, royalty and taxes, and state budgets and programs.

6.5 Common Cause Analyses

In addition to the preliminary screening analysis that will be performed to determine worst case reliability, safety, and environmental impacts, applicable "common cause" events will be identified that can affect production and continued operations of the oil and gas infrastructure. A common cause event for this risk assessment is defined as a single event (or closely related set of events) that has the potential to cause failures (and resultant consequences) in more than one node simultaneously. This section describes the common cause analysis approach that will be performed to ensure that potential impacts that can result from a "system of systems" infrastructure will be addressed.

Common cause events may affect nodes that individually do not meet the minimum preliminary screening criteria, but that, because of the common cause effects of certain initiating events or failures, could contribute to a resultant set of consequences which lead to more severe impacts.

Examples of common cause events which will be considered and postulated include:

- Loss of a utility system supporting operations in a wide area (e.g., electric power, fuel gas, waste disposal, injection supply)
- Control system failure that can impact numerous facilities that are tied into the same system
- Natural hazard events (e.g., earthquake, severe weather, volcanic ash fallout) that can affect a wide region that can encompass many infrastructure nodes

An example is provided below to illustrate the common cause issue and how it will be applied.

> **Example:** Assume there are three infrastructure nodes which are Wellsites A, B, and C (Nodes A, B and C) of a certain operating area in a certain infrastructure region. Each of the three wellsites produces a combined crude oil stream from a group of wells. The production from each of the wellsites flows through a set of individual gathering lines that then combine into a downstream pipeline node (Node D) as shown in Figure 6-2. Assume A, B, and C are the only sources of oil to Node D, and that the individual production flow streams from each individual wellsite are low enough that individually, long term loss of flow (i.e., the longest it is determined that it would take to respond and restore flow) from Node A, B, or C alone might not meet the screening threshold for reliability/production

loss. However, when Node D is examined, it is found that one or more specific worst case events would cause loss of flow through Node D that would meet the screening threshold criteria for reliability/production loss. Therefore, not only would Node D need to be examined in more detail for individual events that could occur at that node, it would also need to be determined whether or not there are other common cause events that would cause loss of production from all three of the other nodes (i.e., Nodes A, B, and C) such that the resulting combined loss event (loss of production from all three wellsites) would meet the screening criteria. A common cause event for this case that might need to be considered would be an earthquake or other natural hazard event in the area that could potentially damage all of the pipelines from each of the wellsites and the combined flowline or gathering line.

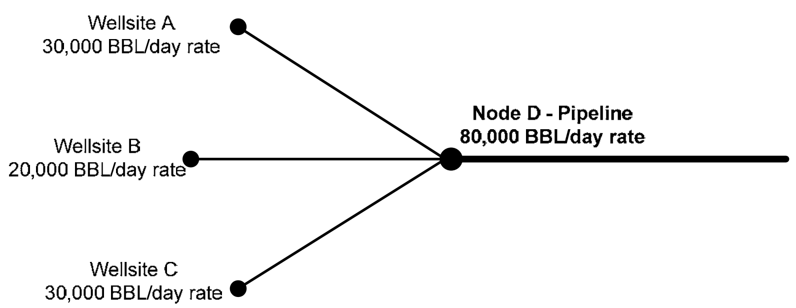

Figure 6-2 Example from Nodal Diagram for Common Cause

6.6 Results of Preliminary Screening

The product of the preliminary screening will be a list of the infrastructure nodes within the scope of the risk assessment that are potentially significant contributors to risk in at least one of the three consequence classifications. The results of the screening will identify those nodes and consequence types for specific areas where risk is low (due to low consequence) and where additional resources will not be needed to analyze the area in more detail. Screening results will be recorded in the risk assessment database prior to further detailed risk analysis activities.

7 OPERATIONAL HAZARDS ASSESSMENT

7.1 Introduction

Safety, environmental, and reliability risks will be estimated for Alaska's oil and gas infrastructure in this risk assessment method. These risks result from infrastructure operational hazards, which may be caused by component malfunctions over time or failure caused by natural hazard events that impose an extreme load on the equipment. Modeling of operational hazards will be done in more detail than modeling for natural hazard-induced failures and will require a different risk assessment methodology than the one described in Section 8 for natural hazards. This section describes the methodology that will be used to model the risks from operational hazards and the consequences they create. This is hereafter referred to as operational risk.

7.1.1 Definitions of Operational Risk

The operations of the Alaska oil and gas facilities can pose risks to three targets:

1. Public citizens located in close proximity to the infrastructure facilities, and personnel working within the boundaries of the infrastructure facilities. This is defined as "Safety Risk."

2. Land, water, flora, and fauna adjacent to the infrastructure. This is defined as "Environmental Risk."

3. Lost or reduced production from the infrastructure facilities resulting in loss of revenue to the State. This is defined as "Reliability Risk."

Operational hazards that will be considered in this portion of the risk assessment include the hazard categories that were highlighted in the stakeholder consultation process (Task 1 of the project) and documented in the Interim Report, shown in Table 7-1 below.

Table 7-1 Operational Hazard Classes for Analysis

Operational Hazard Class
Fires and Explosions (which can result from hydrocarbon releases)
Spills and leaks (e.g., due to natural aging process – corrosion, abrasion, wear and fatigue)
Equipment malfunctions
Loss of infrastructure support systems (e.g., power)
Changes in process conditions (e.g., composition– heavy oil, increased quantities of solids produced, increased gas to oil ration, water influx, H_2S generation, and throughput decline)
Human errors (due to worker fatigue, not following proper procedures, resource availability, etc.)

Additional classes or specific operational hazards may be added to this list during the data collection process and during the process of identifying specific hazardous events as described in Section 7.1.5.

It should be emphasized that the types of risk in this project are episodic in nature. The methodology that is presented does not include the assessment of chronic risk, such as the impact of continuous emissions of a toxin which could impact human health. In addition, the environmental risks examined in this effort are restricted to "spill risks" from hydrocarbon production and seawater streams only. They do not include other types of environmental impacts such as air pollution due to emissions or runoff due to construction/repair activities.

Methodologies for addressing safety risk, environmental risk, and reliability risk are presented separately because, by definition, they affect different elements. However, there are tasks that are common to all three consequence types. Figure 7-1 presents an overview of the top-level tasks for the operational hazards risk assessment.

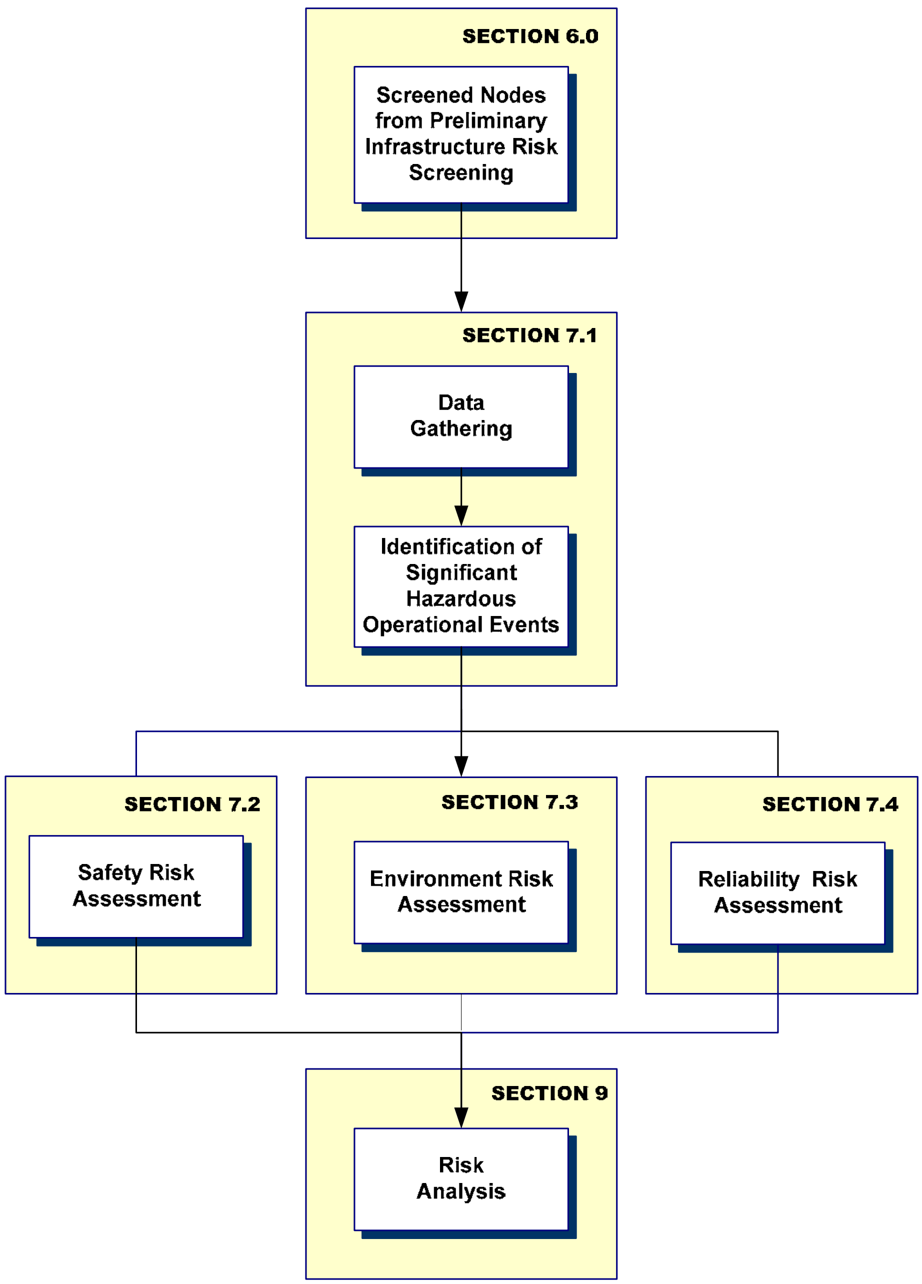

Figure 7-1 Top Level Operational Hazards Risk Assessment Tasks

7.1.2 Data Needs

Generally, two sources of data are required for modeling equipment malfunctions and operational risk: 1) facility-specific information and data, some of which is publicly available and some of which must be supplied by the infrastructure facility owners/operators, and 2) generic industry-wide reliability data that is publicly available to the project team.

The following sections discuss and present examples of these two types of data sources.

7.1.3 Facility-Specific Information and Data

Up-to-date, facility-specific data is essential for performing a realistic operational risk assessment. Some information can be obtained from public sources such as state agencies (e.g., Alaska Department of Environmental Conservation and the Alaska Oil & Gas Conservation Commission) or from industry internet sites (e.g., APSC, BP, or ConocoPhillips). However, facility operators have the information necessary to operate and maintain their facilities. Acquiring direct data from the facility owners/operators relating to operations, maintenance and inspection programs, and equipment design will help ensure the results of the risk assessment are appropriate and specific for the existing oil and gas infrastructure in Alaska.

Table C-1 and Table C-2 in Appendix C present the types of facility specific data that are needed for implementation of the operational risk assessment. The two tables have been divided into data requirements for facilities and major pipelines, respectively. Table C-3 in Appendix C provides a list of the required publicly available data for facilities.

7.1.4 Generic Industry-wide Reliability Data

In addition to facility-specific data, the risk assessment will use generic industry-wide reliability data (primarily equipment failure rates) from public sources. Facility-specific data is often statistically insufficient for a risk assessment. As a result, there is a need to augment this data with published failure data (also known as generic data) and to utilize existing, industry-practiced techniques for combining the generic and facility-specific data.

Table C-4 in Appendix C provides a list of industry-wide data sources that will be required for the risk assessment. Most of these data sources are currently available in the project team's in-house library.

7.1.5 Identification of Significant Equipment Failures

The starting point for identification of significant operational hazardous events is the list of screened nodes produced by the preliminary screening of infrastructure (described in Section 6). Each node contains equipment that upon failure could potentially create significant safety, environmental, and/or reliability consequences. A Failure Modes and Effects Analysis (FMEA) will be used to analyze typical failures in the major component/systems of each facility type being assessed (defined in Section 5.3, e.g., gas handling facilities or common pipelines). The FMEA is a systematic approach that can be used to identify equipment/failure mode combinations that are deemed to be significant operational hazardous events. The event identification process will be parallel for similar facilities with common components and systems.

The FMEA technique is a well-established methodology that can be applied for this purpose.[31] The FMEA tabulates failure modes of equipment and their effects on the facility operations. The failure mode describes how the equipment actually fails (e.g., leaks, ruptures, or long downtime).

The effect of the failure mode is determined by the facility response to the equipment failure and the local environment (e.g., Is the failure in a node that is in an environmentally sensitive area or near a worker or public population?). The FMEA identifies single failure modes that either directly result in or contribute to an accident or a facility outage. Although human errors are discussed here, the effects of a mal-operation as a result of human error are normally indicated by an equipment failure mode.

As shown in the following Figure 7-2, the inputs to the FMEA task are the screened nodes and facility-specific information and data, and generic industry-wide reliability data. The results are a list of significant hazardous operational events for each node that merit further assessment following the preliminary screening of infrastructure.

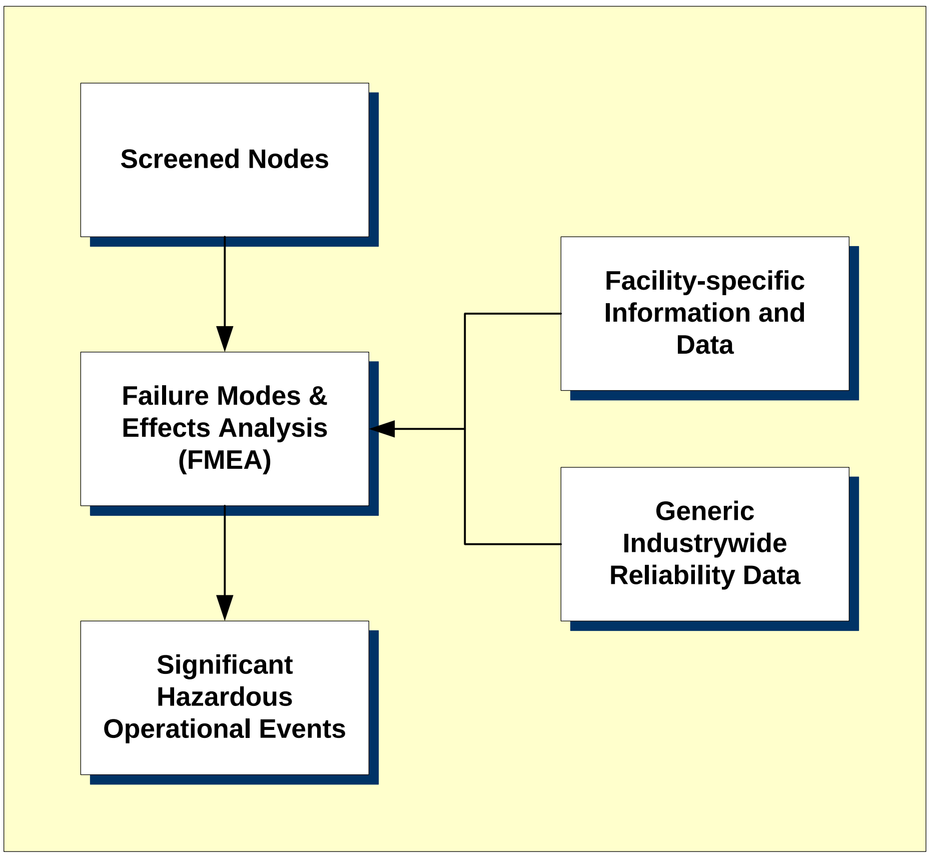

Figure 7-2 Identification of Significant Hazardous Operational Events

7.2 Safety Risk Assessment

7.2.1 Safety Risk Assessment Overview

The purpose of the safety risk assessment is to estimate potential harm to workers on site at infrastructure facilities and to the public in nearby communities. By quantifying the risks, features of the infrastructure that govern the risks and improvement opportunities can be identified. The quantitative results provide a measure of the safety of the infrastructure components. In a quantitative risk assessment individual hazards are examined in the context of overall risk.

The operational risk assessment process for safety risk is depicted in Figure 7-3. The first priority is to identify "incidents," which are release cases for hazardous materials at each node. The task of incident identification will be performed through the application of the FMEA process as described in Section 7.1.5.

After the incident scenarios for each node have been identified, the safety risk calculation will entail three major tasks:

1. Consequence Analysis – Evaluation of physical effects of incidents on people

2. Likelihood Analysis – Estimation of incident frequencies

3. Risk Calculation – Calculation of risks, which are a combination of likelihood and consequences/impacts, and presentation of results

Risk is then calculated using the "risk triplet" model, shown in Equation 7-1:

$$\mathcal{R} \equiv \left\langle \mathcal{E}_i, C_i, \mathcal{L}_i \right\rangle_n$$

Equation 7-1 Risk Triplet Model

Where:

$\mathcal{R}$ = Calculated risk

$\mathcal{E}_i$ = Significant Incident Scenario i (from the FMEA Hazard Events Identification process)

C_i = Event i consequence (from the Consequence Analysis)

$\mathcal{L}_i$ = Event i Likelihood (from the Likelihood Analysis)

n = Number of significant incident scenarios

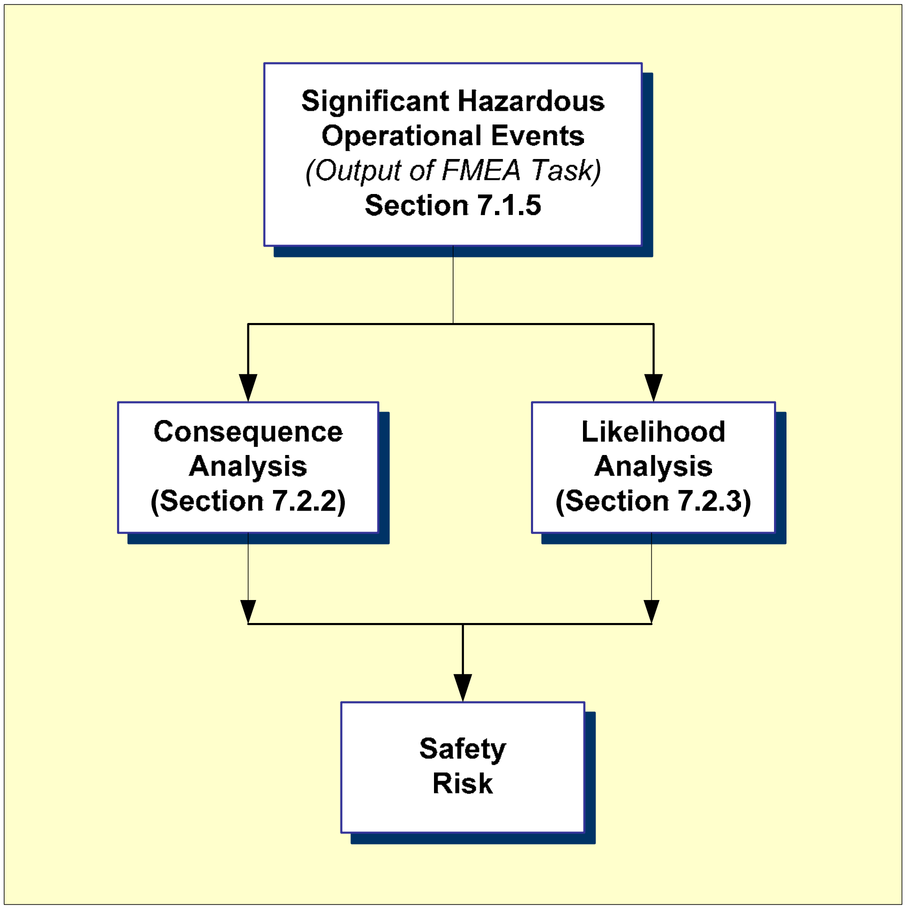

Figure 7-3 Operational Risk Assessment Process - Safety Risk

7.2.2 Consequence Analysis

Operational events with safety hazards are initiated by a loss of containment followed by a hydrocarbon release or spill, which results in a fire or explosion. If the released material is also toxic, there is the additional possibility of toxic impact on people. In this project, it is expected that safety risks will be dominated largely by scenarios involving the ignition of uncontained hydrocarbons. Therefore, no plans are in place for modeling potential toxic impact on people. Only hydrocarbon release events, such as those shown in Figure 7-4, will be analyzed with a detailed modeling process when required.

Therefore, the consequence analysis is concerned with the following issues:

1. The quantity and duration of the hydrocarbon material released.

2. The release distance and form of the released material into the atmosphere.

3. The final form of the released material.

Figure 7-4 illustrates the modeling required for estimating the safety hazard from a hydrocarbon release event. Given a significant hazardous operational event involving a hydrocarbon material release, the first step is to estimate the release amount. The release amount will depend on the hole size, process conditions (in particular, upstream pressure), and process material properties. The material will be released as a gas, a liquid, or a flashing liquid (two-phase flow). Once the magnitude of the hazardous event has been determined, the potential impact on local operations personnel and/or the public will be determined based on relevant staffing and population data.

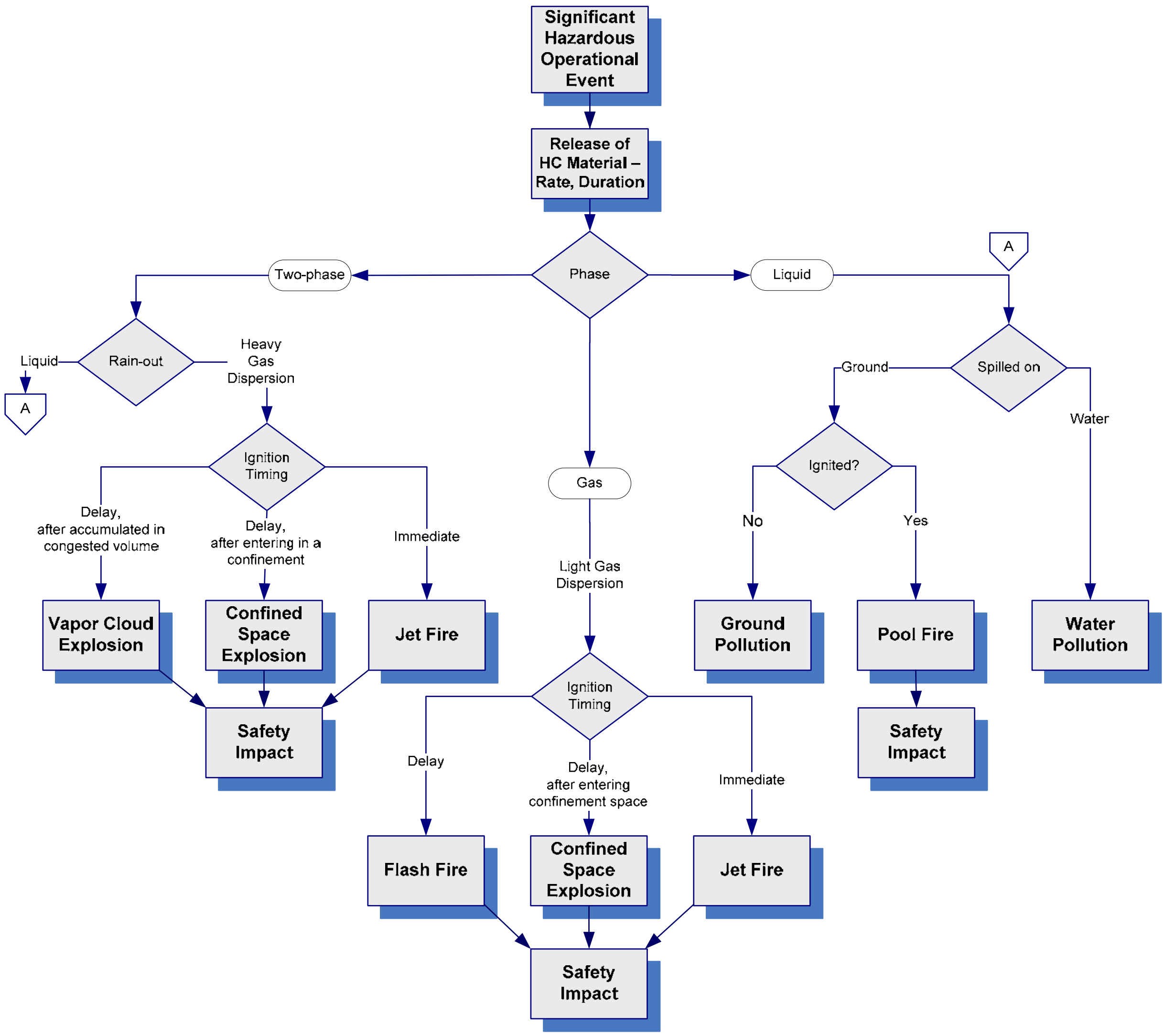

Figure 7-4 Overview of Potential Incident Outcomes upon a Release of Hydrocarbon

As a result of existing regulatory requirements for facilities covered by Process Safety Management (PSM) standards, facility siting studies should already have been completed by facility owners/operators for all PSM-covered infrastructure facilities. Such facility siting studies include identification and modeling of worst-case release events as well as mitigations that are in place to protect people from such incidents. Facility siting studies will be requested from facility owners/operators, which will be used in lieu of performing redundant modeling of hydrocarbon releases for infrastructure facilities.

Detailed modeling of hydrocarbon releases will be required for infrastructure that does not have a completed facility siting study available for review. Where required, hydrocarbon release modeling will be accomplished using software and specific infrastructure data and information about possible hydrocarbon releases. A discussion of the factors that weigh into detailed modeling of hydrocarbon releases is provided in Appendix D.

7.2.3 Likelihood Analysis

The likelihood analysis is comprised of two consecutive tasks: 1) estimation of the failure frequency (i.e., likelihood of failure) for components followed by 2) analysis of the frequency (i.e., likelihood) of significant hazardous operational events.

7.2.3.1 Failure Data Analysis – Estimating Failure Frequency for Facility Components

Generic industry-wide reliability data will be used as the starting point for estimating the failure frequency for facility components. However, in order to estimate component failure frequencies more specific to Alaska's oil and gas infrastructure, facility-specific failure data must be combined with generic industry-wide reliability data in the failure data analysis process. One example of a consideration that would be reflected in updating generic data would be extreme cold and other factors that are specific to Alaska and/or specific facilities. This includes site specific conditions (like cold temperature effects on inadequately protected equipment) that will result in the selection of higher failure rates than generic data would otherwise show for some types of equipment (particularly for standby equipment like safety valves). Of course, making these kinds of failure rate adjustments will be dependent on the availability of site-specific or Alaska-specific data. The core of the methodology for incorporating facility-specific failure data is found in Bayesian Updating, which is a statistical probability tool that has been used in probabilistic risk analysis for over 20 years in many industrial applications. The Bayesian estimation of a failure rate consists of three major steps:

1. Prior information about the failure rate is quantified (i.e., the prior distribution, which is obtained from the industry data).

2. Facility failure data are collected to form a likelihood function.

3. The posterior distribution is constructed by combining the prior distribution and the likelihood function using the Bayesian theorem.

A published paper on the Bayesian data analysis approach is included in Appendix E of this report.[32] The method presented in the paper will be employed in the data analysis of the safety risk assessment. Figure 7-5 depicts a flowchart of the failure frequency estimation process for facility equipment, such as pressure vessels and rotating equipment. For pipeline segments, an additional input to the Bayesian method called the "pipeline score" is included. The "pipeline score" will be calculated as described in Section 7.2.3.2.

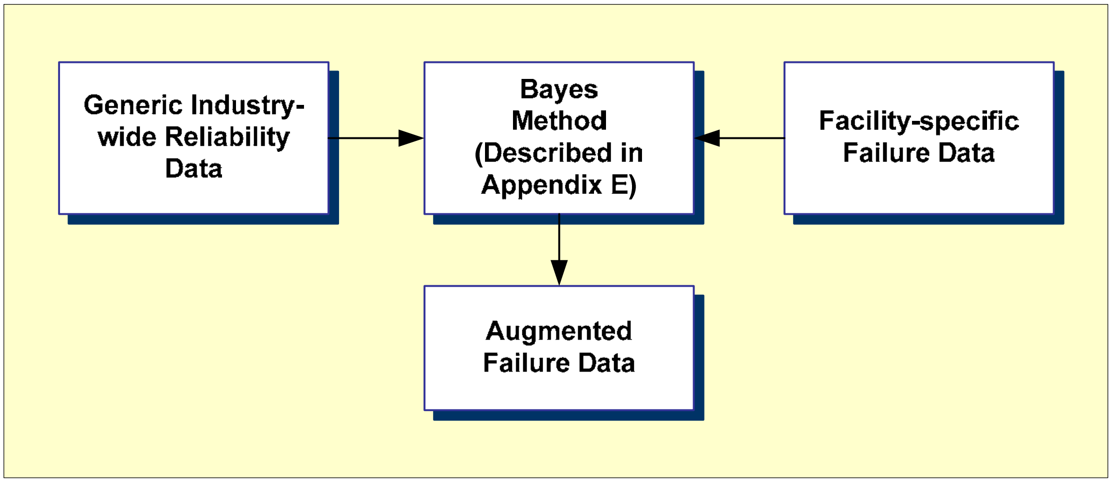

Figure 7-5 Failure Frequency Estimation Process for Facility Components (excludes pipelines)

7.2.3.2 Pipeline Scoring Method – Estimating Failure Frequency for Pipeline Segments

The methodology for the failure frequency estimation of a pipeline segment adds the scoring method to the Bayesian method of failure data analysis discussed in Section 7.2.3.1. This additional step is referred to here as the "scoring method" and is one approach to addressing consideration for existing integrity management systems that may be in place for pipeline integrity assurance. Additional evaluation is needed for pipelines for this study due to the aging issue of Alaska's pipeline infrastructure, which has resulted in previous loss of containment incidents, and because pipelines are exposed to a harsher environment than other types of facility components (which may be housed inside modules or enclosures) and may be subject to external effects and corrosion factors. Figure 7-6 shows a flowchart for the failure frequency analysis of pipeline segments.

Numerous parameters must be taken into consideration for the evaluation of pipeline integrity. As shown in the upper portion of Figure 7-6, the Muhlbauer approach, which may be employed for "pipeline scoring," incorporates the following four elements:[33]

1. Operating and Maintenance Index
2. Design & Construction Index
3. Corrosion Index
4. Third-party Index

Table F-1 through Table F-4 in Appendix F provide lists of parameters to be collected and evaluated for each segment (node) of a pipeline. Each pipeline segment can receive a score between 0 and 400. The scores are assigned based on the pipeline segment historical records and the applied management practices. Scores will be assigned using professional judgment predicated on current best practices and standards.

While the methodology illustrated in Figure 7-6 and described here is a preferred approach to gain a more accurate estimate of failure frequencies for pipeline segments, and for consideration of existing pipeline integrity management systems it is understood that obtaining data to support risk assessment activities can be a challenge. In order for this approach to be effective a significant amount of information from the facility owners/operators will be required to understand their operations and maintenance practices, equipment design, and corrosion inspection and protection programs. Without this data, the scoring method cannot be incorporated into the likelihood analysis. In this case, equipment failure rates will be taken directly from generic industry-wide reliability data or estimated using available data in conjunction with the Bayesian updating process described in Section 7.2.3.1 and Appendix E.

An issue that has been raised regarding future operations of TAPS is the effect of heavier oils that may act differently than what has been experienced thus far. Introduction of such oil into the pipeline may or may not significantly influence the failure rates of infrastructure equipment. The risk assessment will address this issue with experts and appropriate references in the corrosion and pipeline field to obtain input on the influence of future oil changes on failure rates (for failure mechanisms of interest) and incorporate this information into the equipment failure rates as appropriate. Based on current indications, little data exists on this subject. If it is discovered that data is scarce to the point that the topic cannot be legitimately addressed the risk assessment may only recommend that further studies are needed on this subject.

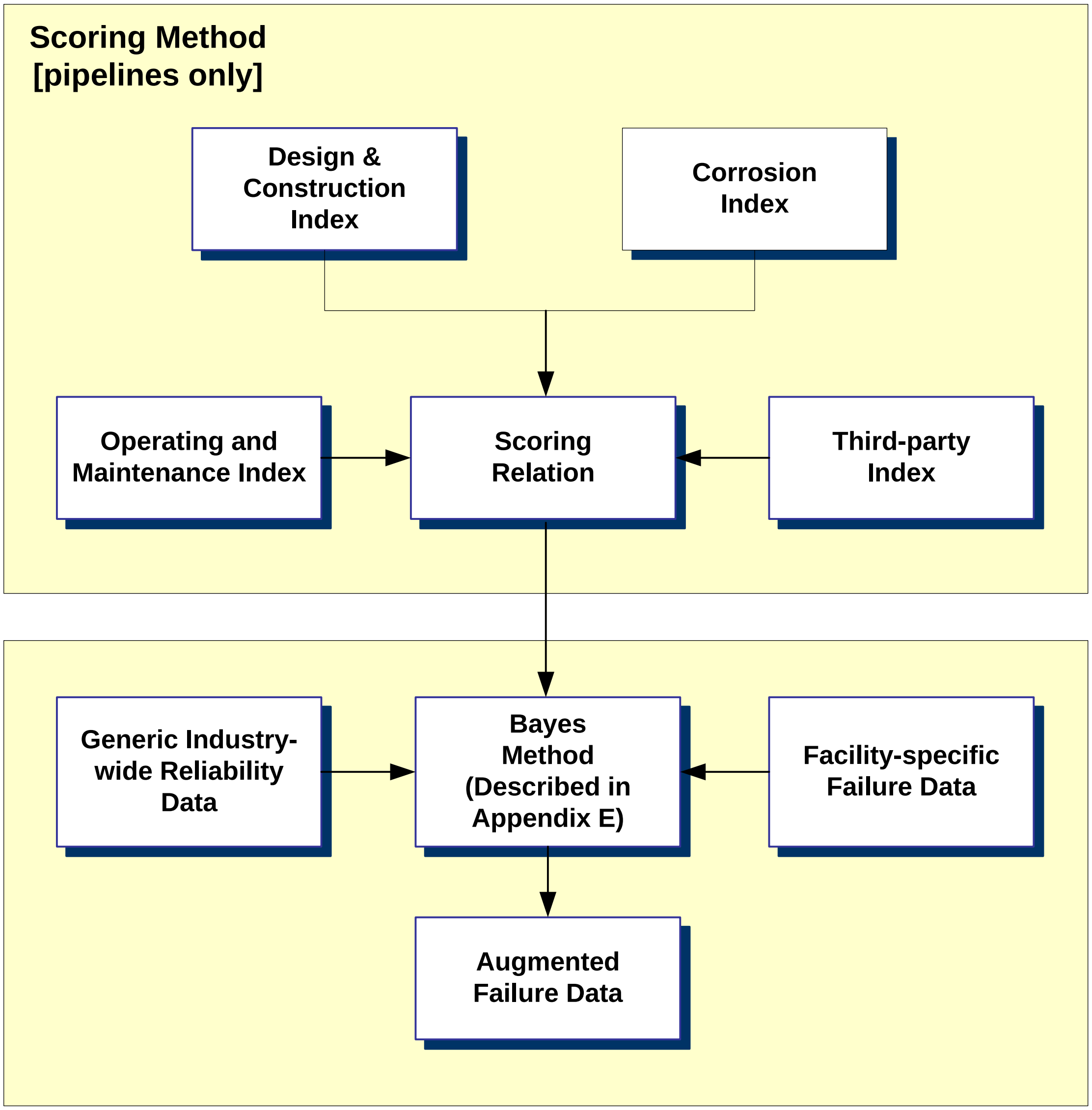

Figure 7-6 Failure Frequency Estimation Process for Pipeline Segments

7.2.3.3 Significant Hazardous Operational Event Frequency Analysis

Event tree techniques will be used to identify and estimate the frequency of operational hazardous event outcomes. The event tree model is comprised of three elements:

1. An initiating event
2. A set of enabling events
3. A set of hazardous operational event outcomes

Initiating events (significant equipment failures) will be identified by performing the FMEA for the nodes that passed the preliminary screening. The combination of the initiating events and the estimates of the failure frequencies, obtained as described in Sections 7.2.3.1 and 7.2.3.2, will enable the development of a representative set of event trees to identify and estimate the frequency of possible operational hazardous event outcomes.

Figure 7-7 is a simplified conceptual event tree showing sequences leading to one of three operational hazardous event outcomes, given an initiating and two enabling events. In this example, a gas is accidentally released from a pressurized containment failure (Initiating Event). If ignited immediately (Enabling Event 1), the release turns into a jet fire (Hazardous Operational Event Outcome 1). If the released gas is not ignited right away, it may find an ignition source downstream (Enabling Event 2) and turn into a flash fire (Hazardous Operational Event Outcome 2). Finally, if it is not ignited at all, the gas dissipates without any harm (Hazardous Operational Event Outcome 3).

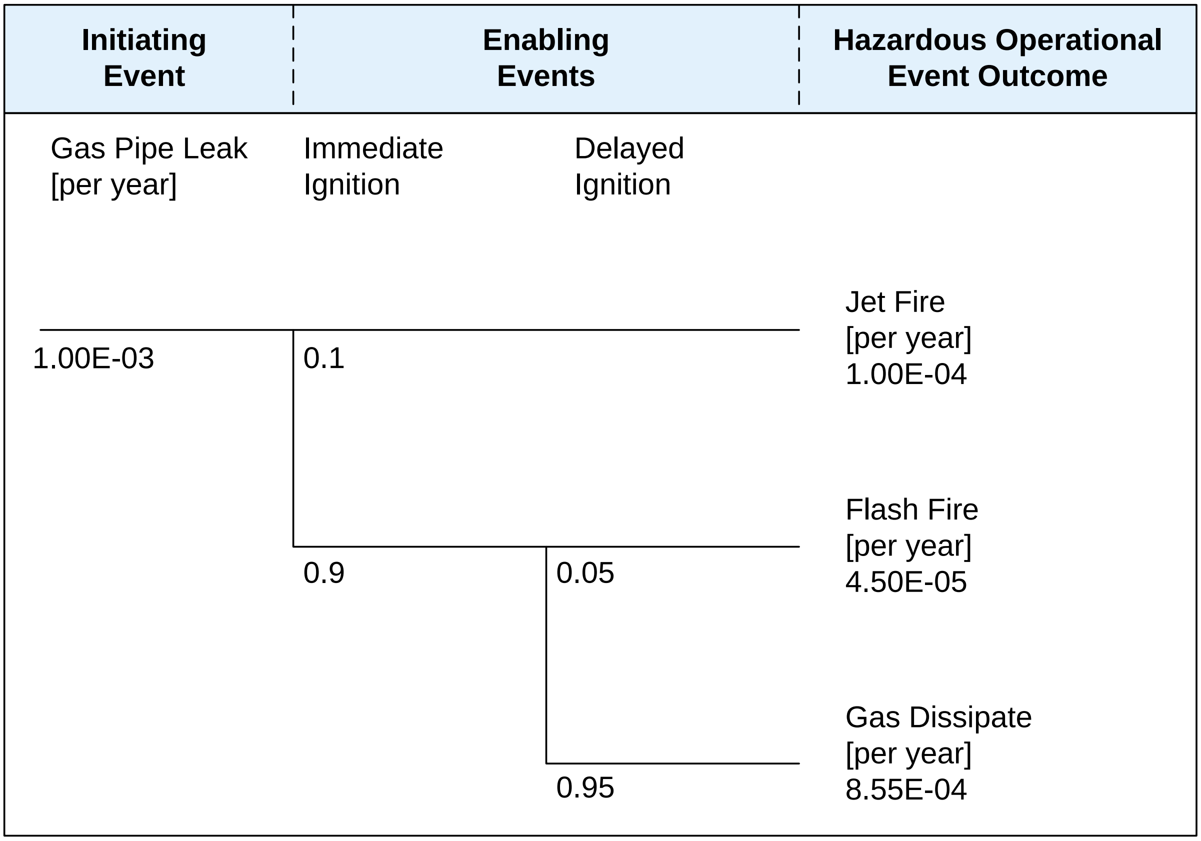

Figure 7-7 Event Tree Example for Hazardous Operational Outcomes

Event trees will be developed for several various sizes of releases that may occur with equipment failures. The actual event trees to be developed in the implementation phase of this project will be more complicated than the one shown in Figure 7-7. They may include more enabling events, such as weather conditions and release location, and additional outcomes. In some cases, the enabling conditions (like severe cold) may be used to affect failure frequencies rather than add branches to the event tree. In addition, if information is available, there are circumstances when failure likelihoods will be adjusted to reflect local conditions such as the potential for human errors.

7.3 Environmental Risk Assessment

Loss of containment from vessels and pipelines containing liquid may result in a spill on the ground or into water, depending on the location of the spill. The environmental risk assessment is concerned with the likelihood of spills of hydrocarbon liquids or seawater to the external environment.

Figure 7-8 presents the environmental risk assessment process. As shown, the environmental risk assessment will estimate the size and type of accidental spill in the external environment.

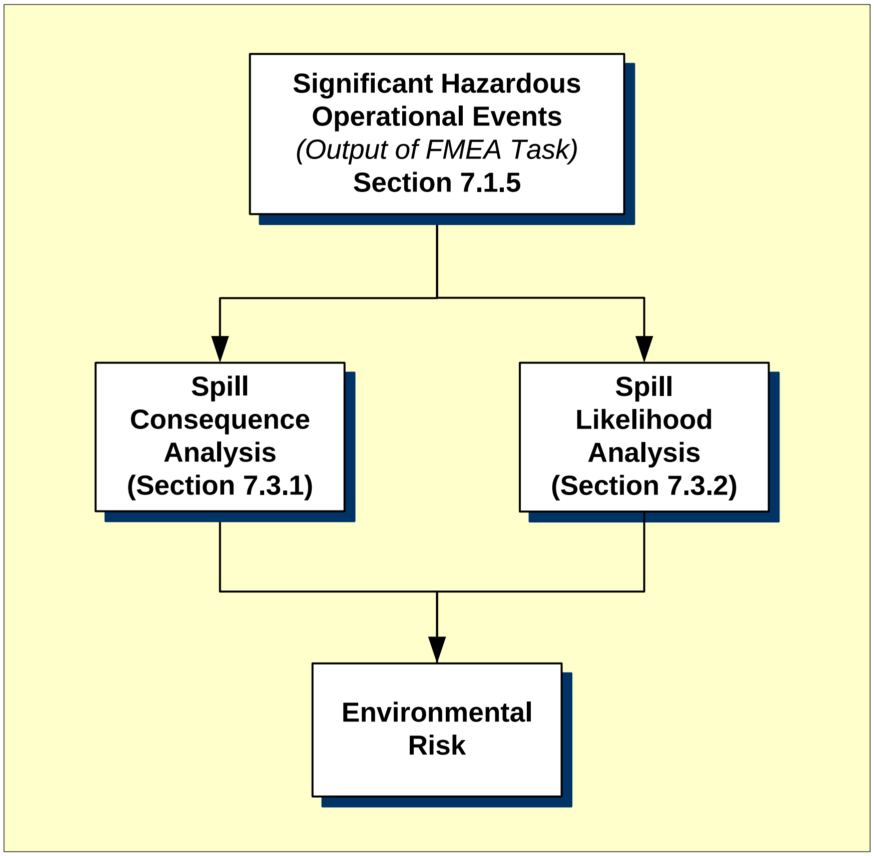

Figure 7-8 Environmental Risk Assessment Process

The process of environmental risk assessment is straightforward, starting with significant hazardous operational events that potentially result in significant spill scenarios. During the preliminary risk screening process, nodes with potentially significant environmental risks will be identified (See Section 6). These screened nodes will be further examined starting with the use of the FMEA technique discussed in Section 7.1.5 to identify equipment failures that could create potentially significant environmental consequences.

The FMEA process will define a range of release events and assess a time frame in which such a release would be detected. It is recognized that the largest leak rates may not always result in the largest release quantity due to the time required to detect smaller, but still significant releases. It is assumed that detection of release events will be based on operational measures such as routine monitoring (i.e., once per shift or once per day). These assumptions will differ depending on the infrastructure node. For example, different detection times will be applicable to aboveground, underground, and offshore situations. To develop these estimates, detailed data (regarding leak detection capabilities, monitoring/ schedules, operator rounds, etc.) will be needed from the owners/operators of the infrastructure being assessed.

7.3.1 Spill Consequence Analysis

The location of a spill can be at process facilities, along a pipeline corridor, or offshore. Scenarios will be postulated for varying seasonal conditions. The severity of the impacts of a spill is dependent on many factors including the quantity and type of materials that are released, the environmental sensitivity of the surroundings, and the effectiveness of mitigation/remediation efforts. For example, a relatively small leak (just above 10 barrels) of crude oil to a fast moving waterway (either a major river or sea with intense currents) could cause significantly higher impacts due to its ability to spread and non-recoverability, when compared to a much larger size crude spill (above 1000 barrels) to a frozen waterway (where recovery and remediation is much easier).

There are many types of detailed analysis tools that can be used for rigorous fate and transport modeling that can predict the potential impacts of a spill to the environment. However, it is not the intent of this study to perform a detailed environmental risk assessment for each potential spill scenario that is examined. The proposed approach to assessing environmental impacts for liquid hydrocarbon and seawater spills from the existing oil and gas infrastructure will be a customized environmental consequence scoring model that considers each of the relevant contributing factors that combine to play a role in the significance of spill impacts. Accidental spill consequences will be assigned using the environmental consequence scoring method that is described below for all operational hazard scenarios considered. Based on this approach, each spill scenario will be analyzed and an appropriate environmental consequence score will be calculated which equates to a corresponding environmental consequence category.

7.3.1.1 Factors for Environmental Consequence Ranking

The consequence analysis for environmental consequences will address the various contributing factors that are associated with spill impacts, as described in the preliminary screening approach (Section 6.3). These include:

1. Sensitivity of the surrounding external environment (Note 1)
2. Composition/type of fluid stream that is released (hydrocarbons or seawater)
3. Release quantity or volume of fluid released
4. Recoverability of spill volume and remediation efficiencies

Note 1: When assessing the environmental sensitivity of an area, consideration will be given to definitions such as "sensitive area" and "high consequence area" that have already been developed by regulatory agencies, such as those included in pertinent Department of Transportation regulations and applied by the infrastructure operators. For efficiency, regulatory definitions may be applied when performing project activities such as infrastructure segmentation for pipelines. However, regulatory definitions may not always be appropriate to meet the objectives of the risk assessment as defined by the State. As such, a customized definition of an "area of high environmental consequence" has been developed for this project.

7.3.1.2 Environmental Consequence Categories

The environmental factors listed above will be used to calculate relative scores for each identified environmental scenario of interest. Table 7-2 through Table 7-5 present the scoring approach for each of these factors, and Table 7-6 presents the overall criteria used to assign an environmental consequence category based on a mathematical combination of the indices for each factor.

Release Material Composition Categories

The type of material that can be spilled is a primary consideration in examining the potential environmental risks of unplanned events that can occur during the continued operation of Alaska's oil and gas infrastructure. The Project Team has defined the three categories of materials listed in Table 7-2 which have been defined for purposes of assessing potential risks of unplanned releases. All three types of materials have environmental impact if they are released; however, based on stakeholder input and examination of the consequences of previous releases, it is clear that there are distinct differences in these categories of process materials. If a release event of a "mixed stream" (i.e., one that contains significant amounts of two or more of the materials that are contained in the below categories) is examined, a conservative approach will be taken. That is, the material category with the worst potential environmental consequence will be used when assigning the material composition index for the release event. The focus of this study will only be on hydrocarbon and seawater releases (including produced water), and will not include modeling other types of hazardous substance releases.

Table 7-2 Release Material Composition Categories

Composition	Category Index Number	Explanation
Crude oil or other liquid hydrocarbon (such as diesel)	**3**	A heavy hydrocarbon such as crude oil can have persistent impacts when released to the environment, making it the highest impact of the categories of materials being considered.
Seawater or Produced water (including contamination with small amounts of hydrocarbon)	**2**	Seawater and produced water are assumed to present a lower level of environmental impact than crude oil, but can still have extensive impacts on the environment due to their salinity as well as the small percentage of hydrocarbon present in produced water after treating (from a volumetric perspective).
Natural gas liquids (NGLs)	**1**	Spills of these materials are expected to have little environmental impact since they are highly volatile and would be expected to disperse quickly into the environment.

Release Quantity Categories

Release quantities for various hole sizes from leaks and ruptures of equipment/components in the nodes of interest will be estimated by considering process flow rates, release detection time (based on leak detection and operations personnel monitoring of the area), and isolation capability once a leak is detected. The release size will then be categorized using the category boundaries provided in Table 7-3. This set of release quantity categories has been established based on spill sizes that are considered to be of significance[27] which considers the range of production flows from small facilities (e.g., Cook Inlet facilities producing a 100 barrels a day) to the TAPS, where daily flows are 600,000 to 700,000 barrels per day.

Table 7-3 Release Quantity Categories

Release Quantity	Category Index Number	Explanation
Large release (>10,000 barrels)	**6**	Release quantities will be assessed based on normal process flow, the nature of the worst-case release considered, and the expected detection and isolation time.
Medium Release (1,001 to 10,000 barrels)	**5**	
Small Release (10 to 1,000 barrels)	**4**	

Note: The release quantity categories are assigned numbers from 4 to 6 in order to reflect the overall importance of the spill size compared to the other contributing categories (i.e., release quantity is more heavily weighted than the other factor categories, which have an index range from 1 to 3). This also allows the environmental impact to reflect an approach that adjusts spill size by expected recoverability (i.e., subtracting the recoverability category from the release quantity category) to represent the impact of the material which may actually remain in the environment long term.

Release Recovery/Remediation Factor Categories

The ultimate environmental impact of a spill is affected not only by the nature of the material released and the size of the initial spill, but is sensitive to the ability to recover the fluids before long-term damage is done or potential damage is remediated. Table 7-4 provides a description of the recovery/remediation categories. These category values (1 to 3) are subtracted from the spill quantity category index numbers to reflect the risk reduction impact of recovery/remediation.

Table 7-4 Release Recovery/Remediation Factor Category

Recovery/Remediation Capabilities	Category Index Number	Explanation
Little to no ability to recover/remediate this type of release	1	This category includes: • Direct spills to moving bodies of water other than contained entirely on ice (such as ocean/sea, river systems, and tributaries) • Spills to subsurface areas • Other situations assessed as difficult to recover (including requiring input from State and remediation experts
Limited to moderate capability to recover/remediate this type of release	2	This category includes: • Spills to land and tundra in other than frozen conditions • Spills to unprepared surfaces (i.e., prepared surfaces include gravel pads which have been laid for remediation ease) • Other situations assessed as limited to moderate to recover (including requiring input from State and remediation experts)
Very effective capability to recover/remediate this type of release	3	This category includes: • Spills in winter conditions contained on ice or recovered from frozen land or tundra (i.e., limited migration) • Spills to gravel pads or other prepared surfaces where recovery can be accomplished by direct removal of contaminated materials.

Relative Environmental Sensitivity Categories

Any accidental spill of hydrocarbon or seawater has some environmental consequence. However, the impact of this consequence has the potential to vary significantly based on the specific location in which the spill occurs, and the natural resources that are present there. As such, environmental sensitivity has been incorporated into the ranking process using stakeholder recommended sensitivity factors as listed in Table 7-5 below. The reader should recognize that these categories are intended only to help rank the events on a relative basis; efforts at some level of resource investment should be made to prevent unplanned releases.

Subjective judgments will need to be made when assigning the relative categories defined in Table 7-5 as a way to quantify the sensitivity of the environment. Input from the State and other environmental experts as it applies to the relative ranking for the scenarios will be considered, based on the potential severity of environmental impacts.

Table 7-5 Local Environment Sensitivity Categories

Type of Environment	Category Index Number	Type of Environment
Waterways	**3**	This category includes: • Waterways or direct pollution routes to waterways that support commercial fishing, aquaculture, or subsistence activities
Sensitive Lands (including surface and subsurface areas)	**2**	This category includes: • A land area that supports unique flora and fauna or wildlife breeding and migratory areas, which may support subsistence hunting activities (e.g. tundra or wetlands) • An area that encompasses a cultural or historical site • A Recreational Area (defined as an area that supports hunting, fishing, hiking or other outdoor recreational activities) • Areas that have been branded based on pristine conditions and which support tourism activities
Other Lands	**1**	This category includes: • A land area (surface or subsurface) not defined as "sensitive" in Category 2 above.

Calculating Environmental Consequence Categories

An environmental consequence score will be calculated for each of the release events that are considered, based on the index values that are assigned in each of the above contributing factor categories. The overall environmental consequence score will be calculated using Equation 7-2:

$$\mathcal{N}_i = M_i * (Q_i - R_i) * S_i$$

Equation 7-2 Environmental Consequence Scoring Calculation

Where:

$\mathcal{N}_i$ = Event i Calculated Environmental Consequence Score (1 to 45)

$\mathcal{M}_i$ = Event i Material Composition Index (1 to 3)

$\mathcal{Q}_i$ = Event i Release Quantity Index (4 to 6)

$\mathcal{R}_i$ = Event i Recoverability/Remediation Index (1 to 3)

S_i = Event i Environmental Sensitivity Category Index Number (1 to 3)

Example calculation:

A significant release of crude oil (M = 3) that is 2,000 barrels in size (Q = 5) in an area of very high sensitivity (S = 3), but where recovery and remediation efforts can be highly effective (R= 3), would be scored as:

$\mathcal{N}_i$ = 3 x (5-3) x 3 = 18

This approach represents a relative ranking of releases; it cannot be correlated to any physical meaning based on the absolute value of the numbers or index that is assigned to each factor. The value of the overall environmental consequence score can range from 1 to 45, depending on the assigned values of the contributing factor categories. Ranges of the environmental consequence score will then be used to categorize the relative environmental impacts of the potential release scenarios. See Appendix G for example scenarios that have been processed through this model.

Table 7-6 presents preliminary values that will be used for assigning the environmental consequences to each of the potential release events. The definitions and descriptions for the qualitative range of significant environmental consequences for this project in Table 7-6 were derived from input from the stakeholder consultation process that was executed at the commencement of the project.

Table 7-6 Environmental Consequence Categories

Category Number	Environmental Impacts	Consequences Score
3	**Catastrophic** – A significant release to an area of extremely high environmental consequence that causes large-scale, widespread, non-recoverable, irreversible, and long-term damage that is severe. The damage would be considered to be extensive enough that the area would be considered unusable for the foreseeable future. The loss would prevent a return to normal life support and access for the conduct of normal activities that were once supported by the area's resources.	Greater than or equal to 30
2	**Challenging** – A significant release to an area of high environmental consequence that causes widespread and persistent damage to the area, which would cause a disruption in life support and would limit normal use and activities in the area for some time. Remediation would be required and some damage to the area may be irreversible.	Greater than 15, but less than 30
1	**Manageable** – A release to an area of some environmental consequence that results in localized and reversible effects on the environment. Results in some initial disruption of activities in the area, but normal usage can resume in a very short time frame once remediation/recovery activities have been completed.	Less than or equal to 15

7.3.2 Spill Likelihood Analysis

The spill likelihood analysis process for consideration in aboveground and onshore equipment spill scenarios will be conducted using the same approach that was described previously in Section 7.2.3. Hence, the likelihood analysis approach will not be repeated here.

For consideration of offshore and subsea equipment spill scenarios, there are additional contributing factors that play a part in equipment failure (loss of containment) that must be considered such as:

1. Offshore facilities
   - Vessel collision with the facility
   - Dropped objects
2. Subsea pipelines
   - Anchor impacts
   - Natural hazards (e.g., strudeling and scouring)

By incorporating these initiating events into the model, in addition to the consideration of the other factors that were previously discussed, the likelihood of these types of equipment failures will be calculated.

7.3.3 Environmental Risk Calculation

Environmental risk for operational hazard scenarios is based on the likelihood of the spills (i.e., likelihood of equipment failure causing a spill scenario) and the environmental consequence of the resulting spill. The project's approach for developing useful risk information from the operational hazard scenario results is described in Section 9 of this report.

7.4 Reliability Risk Assessment

This section describes the reliability risk assessment methodology for operational hazards. It provides an analysis of the potential for oil and gas production losses that are significant enough to affect the state revenue and budget. These losses can be caused by scenarios that result in total shutdowns or significant reductions in production (depending on duration of the scenario).

The reliability risk assessment begins with the nodes that are identified in the preliminary risk screening that have potentially significant reliability consequences (see Section 6). The overall process for the operational event reliability risk assessment is shown in Figure 7-9.

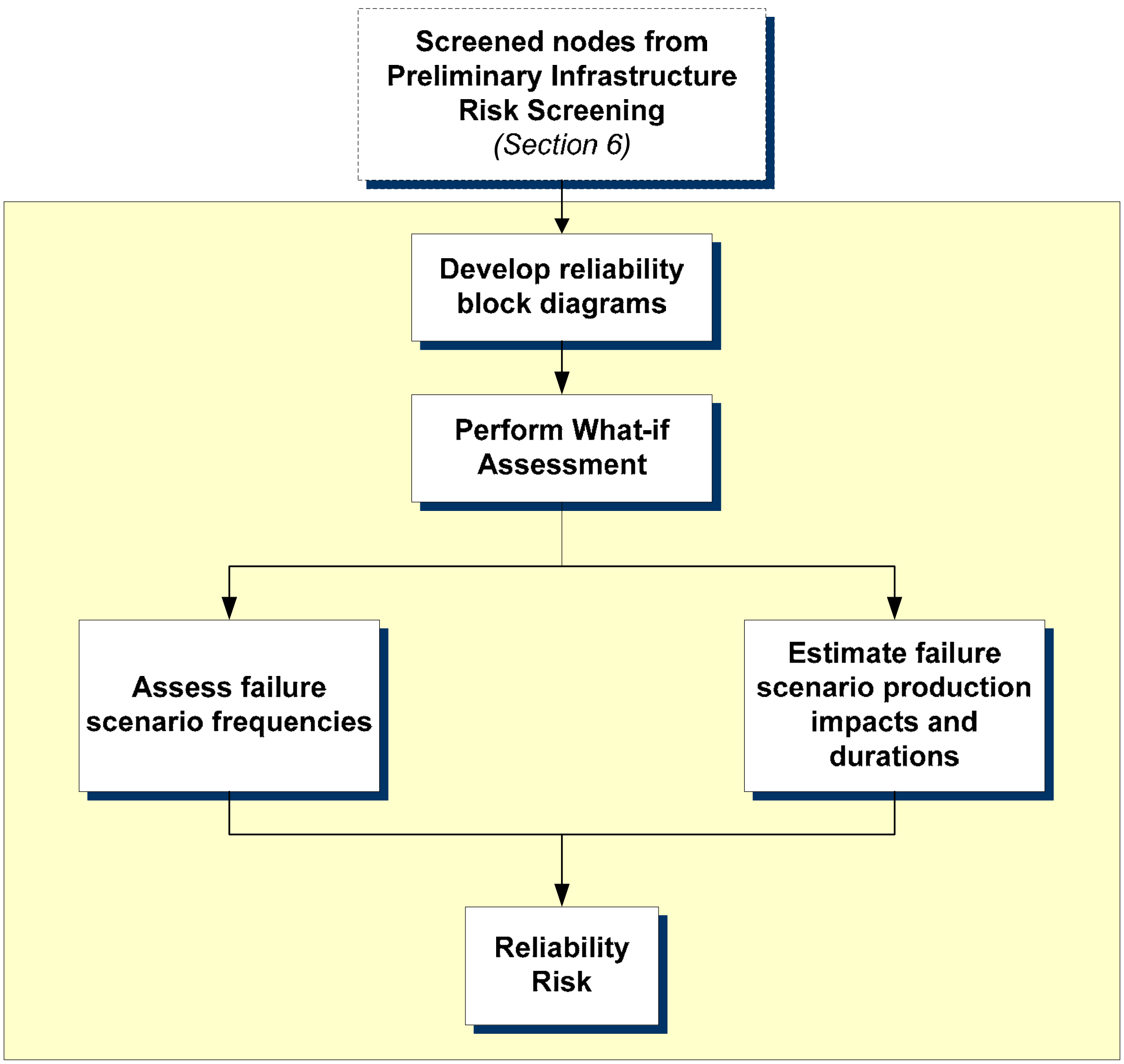

Figure 7-9 Reliability Risk Assessment Process

7.4.1 Reliability Block Diagram Development

To develop and document understanding of the production process flows, the nodal production diagram (described in Section 6.3) will be used in conjunction with reliability block diagrams (RBDs) which will be prepared for nodes/facilities that are within the scope of the reliability risk assessment. The reliability block diagram (RBD) technique provides a systems approach to studying large and complex systems, with special focus on reliability and availability. For example, a two-train processing plant is modeled as a parallel system in which the failure of one train will not shut down the overall production process. However, a failure in a single-train processing plant will halt all production. In addition to documenting train alignment and redundancy, any pertinent alternate operating modes for maintaining production when equipment or system failures occur will also be documented.

If an RBD is available from the facility owner, it will be reviewed and the information will be adapted as needed for purposes of this assessment.

7.4.2 What-if Assessments for Scenario Identification

Using the RBDs and other design information, a what-if analysis will be performed for the node.[31] A what-if analysis is a focused effort to identify scenarios that have a specific consequence, in this case, scenarios that result in significant production losses. These scenarios will include equipment leaks and ruptures, potential fires and explosions that damage production infrastructure, and support system failures. If the node is also included in the environmental assessment (i.e., it was not screened out), the scenario identification effort for environmental and reliability purposes will be combined.

Because of the level of redundancy for most of the active production equipment (like pumps and compressors), and the existing preventive maintenance and spare parts policies for the facilities, routine equipment failures (e.g., a pump failure or electrical switchgear malfunction) are not expected to result in significant downtime. In addition, it is believed that the production impacts caused by these routine failures are already factored into the facility's production schedule and represented in the budget plans for the State. However, if a facility is identified that does not appear to have an approach that addresses routine availability issues, that contribution to production losses can be modeled using the quantitative availability approach described in Appendix H.

7.4.3 Scenario Frequency Estimates

Scenario frequency estimates will be developed for scenarios identified as being of interest for reliability consequences. These estimates will reflect generic industry-wide reliability data, facility-specific data, and engineering judgment. When necessary, event trees will be used to analyze the sequence of failures, operator errors, and other factors that contribute to the scenario occurrence.[34] It is expected that a limited number of representative event trees will be developed to facilitate scenario frequency estimation. The representative event trees will be adapted to reflect local considerations for each node.

An event tree is a logic diagram that visually depicts potential scenarios that can result from a specific failure. Figure 7-10 depicts an event tree analysis of the following sequence:

- A severe compressor leak
- Failure to detect and shut down the compressor, and
- Failure to avoid an ignition source; thereby resulting in an explosion

The event tree also displays other scenarios that are not likely to be as severe as an explosion. In this case, the appropriate initiating frequency and conditional probabilities would be assessed to calculate a scenario frequency for the specific compressor.

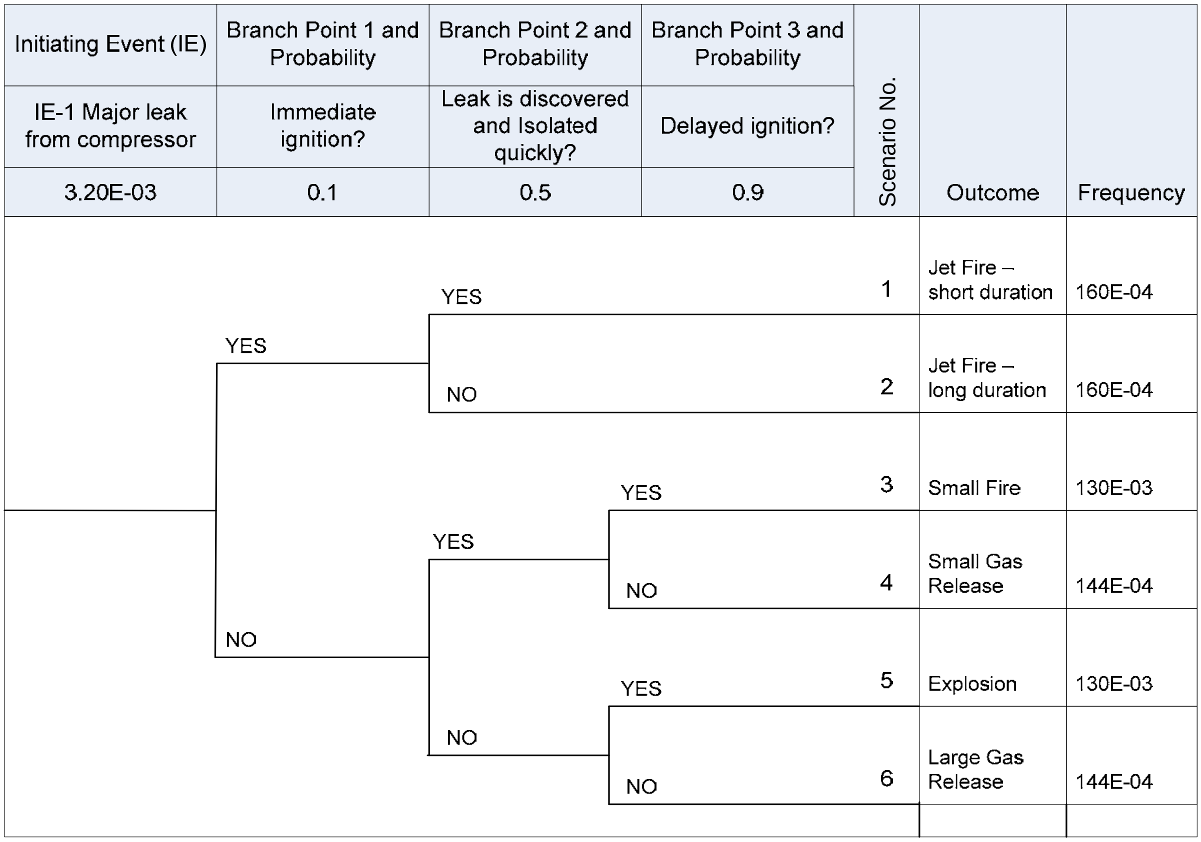

Figure 7-10 Example Event Tree Analysis for a Compressor Leak

7.4.4 Scenario Production Impacts and Durations Estimates

The level of production impact (e.g. 100% of node flow, 50% of node) and the duration of that impact will be estimated for each scenario selected for analysis. These estimates will require facility owner/operator input as they are dependent on the facility owner/operator’s available spare parts, replacement equipment and alternative operating configurations which are normally used to minimize the production impact. These estimates of production impacts, measured in barrels, can be then used by the State to determine revenue impacts to the state budget in consideration of varying oil prices and tax structures.

7.4.5 Reliability Risk Calculation

Reliability risk for operational hazard scenarios is based on the frequency of the initiating event for a scenario, the estimated production impacts, and duration of the event. The approach for developing useful risk information from the operational hazard scenario results is described in Section 9 of this report.

8 NATURAL HAZARDS ASSESSMENT

8.1 Introduction

Natural hazards are phenomena that occur in the environment and are external to the oil and gas infrastructure and its operations. Natural hazards include atmospheric, hydrologic, geologic, and wildfire events that, because of their location, severity, and frequency, have the potential to affect the oil and gas infrastructure adversely. These hazards are typically considered to be "sudden, unexpected, or unusual" and are often called "acts of God."

Natural hazards occur at low frequencies. Typically, occurrence frequencies are lower than 1 in 50 years and can be as low as once in several thousand years. Another defining characteristic is that natural hazards can subject manmade assets to extreme loads. These distinct qualities require a stand-alone assessment of natural hazards separate from operational hazards. A customized natural hazards assessment methodology is presented in this section, which

- Lists natural hazard classes pertinent to the project,
- Outlines data sources and methods for obtaining data,
- Defines a two-step "applicability" and "vulnerability" screening process which will be the focus of the natural hazards assessment, and
- Describes the detailed analysis to assess likelihood of natural hazard event risks on specific infrastructure nodes.

8.1.1 Natural Hazard Classes

Thirteen natural hazards with the potential to affect Alaska oil and gas infrastructure facilities were originally documented in the Interim Report. These hazards represent a broad range of occurrences that could pose significant challenges to various portions of the infrastructure. Many are well understood and were likely considered in the original design of facilities. Some may have been experienced in the past at Alaska oil and gas facilities and subsequently considered as part of reevaluations, upgrades, and additions to the infrastructure over the past 30 or more years of operations. Other hazards are less well known and understood. In fact, some of these hazards are still in the early stages of research and scientific discovery, and do not have long established and codified engineering design standards. Additionally, many facilities are located in remote portions of Alaska where high-quality scientific data has been available for only a short period.

Table 8-1 provides a reorganization of these 13 hazards based on how they will be examined during the risk assessment. In some instances, hazards presented in the Interim Report have been combined or re-titled to better reflect the structure that will be used to implement the methodology. As a result of this reorganization, ten distinct hazard classes will be assessed and are also discussed in Section 8.3.2 of this report, which provides additional information about specific hazard data sources and infrastructure node data sources. No general data sources are provided in Section 8.3.2 for avalanches and forest fires, the last two natural hazard classes listed in Table 8-1. Those types of hazards will be considered on a local basis as they are identified for specific portions of the infrastructure.

Table 8-1 Natural Hazard Classes for Analysis

Natural Hazard Class *(Including natural hazard titles from the Interim Report in italics)*	Description of Hazard (in terms of the ARA Project)
Earthquakes (*Geology* – landslides)	Earthquake hazards include ground shaking and/or permanent ground deformation including fault offset. These mechanisms can result in direct damage to infrastructure or can result in effects like landslides that cause secondary damage (e.g., displacement, burying).
Tsunamis	A tsunami may cause flooding, impact loads from waves or floating debris, or both, and erosion of earth foundations from structures.
Volcanoes (*Geology* – landslides)	Volcano hazards include lava, ash, hot gases, and other materials that can be ejected during an eruption. These materials can cause landslides, avalanches, lahars, etc. that may result in secondary damage to infrastructure.
Coastal Erosion	Coastal erosion, including subsidence, can cause loss of building or equipment support leading to structural damage to infrastructure items.
Permafrost Thawing *(Permafrost Thawing/Climate Change)*	Permafrost thaw can result in loss of building or equipment support leading to structural damage to infrastructure items. Note: There are local causes and effects from long term climate change that can increase permafrost hazards.
Severe Storms *(Severe Storms, Ice, High Winds)*	Severe storms may include high winds, ice buildup, extreme cold, or wave actions that can cause structural damage to buildings and equipment.
Floods *(Floods, Ice)*	Flooding hazards include physical damage/displacement of building and equipment, loss of utility systems, damage to electrical equipment, etc. Note: There are many potential causes for flooding hazards, including severe weather, ice blockage, and long term climate change.
Severe Currents *(Underwater Currents)*	Severe currents can cause damage to offshore platforms and underwater pipelines (e.g., by causing marine vessel collisions or other external impacts).
Avalanche	Avalanche hazards include direct damage (e.g., displacement, burying) to infrastructure and personnel locations, as well as damage to support systems like electrical networks.
Forest Fires	Forest fire hazards include direct damage to infrastructure as well as damage to support systems like electrical networks.

8.1.2 Basis for Natural Hazards Assessment

Section 3 of this report addresses alternatives considered in selecting the natural hazards assessment methodology that is being proposed. Those considerations included the large project scope, diverse hazards of interest, lack of availability of owner/operator natural hazard studies, and lack of consistent industry studies performed independently.

As stated in Section 3, a natural hazards assessment based on consensus procedures developed specifically for risk assessment of oil and gas pipelines was selected for implementation. This methodology was developed by the American Lifelines Alliance (ALA) as a natural hazards assessment process for oil and natural gas pipeline systems.[2] The primary extensions to the ALA approach that that will be incorporated in the natural hazards methodology implementation will be to:

- Make it applicable to areas of the Alaskan oil and gas infrastructure that are not pipelines or pipeline associated facilities (e.g., offshore platforms).

- Address natural hazards within the scope of the project that are not currently covered by the ALA guidance.

The ALA guidelines for natural hazard risk assessment for pipelines were the result of public-private partnership project of the Federal Emergency Management Agency (FEMA) and the National Institute of Building Sciences (NIBS). ALA's goal is to reduce risks to lifelines (utility and transportation systems) from natural hazards. The consensus document to be used for this project outlines a multi-tiered approach and provides options for conducting a customized natural hazard risk assessment.

The ALA guidelines outline a two phase approach; however, this report organizes those phases as parts rather than phases to avoid confusion, since the ARA project already includes a reference to multiple phases of project work. The parts of the study are illustrated in Figure 8-1.

The risk assessment implementation activities (based on the ALA guidelines) will rely extensively on the use of publicly available data, such as hazard mapping information. These hazards maps are typically available from a range of governmental sources including the USGS and FEMA. Similar hazard mapping information will be used for Step 1 and 2 screening, as well as any further detailed analyses that might be completed, unless other more detailed and accurate site-specific information is available from the infrastructure owners/operators.

The entire ALA guidance document is provided in Appendix I. It is not re-written in its entirety in this natural hazards methodology section. This section provides the reader with enough information (along with the ALA guidelines document) to understand the overall project methodology and how unique aspects of the ARA risk project will be addressed. Additional documents are referenced by the ALA guidelines and are listed in Appendix K to this report and will be used in the risk assessment implementation process.

8.1.3 Natural Hazards Assessment Process

The natural hazards assessment begins after completion of the preliminary consequence screening described in Section 6. Only those facility nodes with the potential to incur significant safety, environmental, or reliability consequences will be subject to the natural hazards assessment.

The natural hazards assessment consists of two parts. The first is a two-step natural hazard-specific screening (Section 8.2). Step 1 screens for hazard applicability by identifying those infrastructure nodes located in natural environments where one or more of the ten natural hazards are likely to occur. Step 2 is a vulnerability screening, which identifies the degree to which each node type is susceptible to damage from a specific hazard. This two-step screening process will result in a list of infrastructure nodes that are applicable to a specific hazard and have a high level of vulnerability.

This list of nodes will be moved forward to the second activity of the natural hazards assessment during which a more detailed natural hazard risk assessment may be performed on components or systems that are found to be vulnerable to specific natural hazards, in order to 1) determine the types and extent of equipment damage that might be expected, 2) estimate the frequency of occurrence, and 3) determine the potential consequences that may result from the estimated damage (consistent with the consequence analysis approach described in Section 7. Results of the natural hazards risk assessment will be analyzed and rolled up as described in Section 9 of this report. Figure 8-1 illustrates this process.

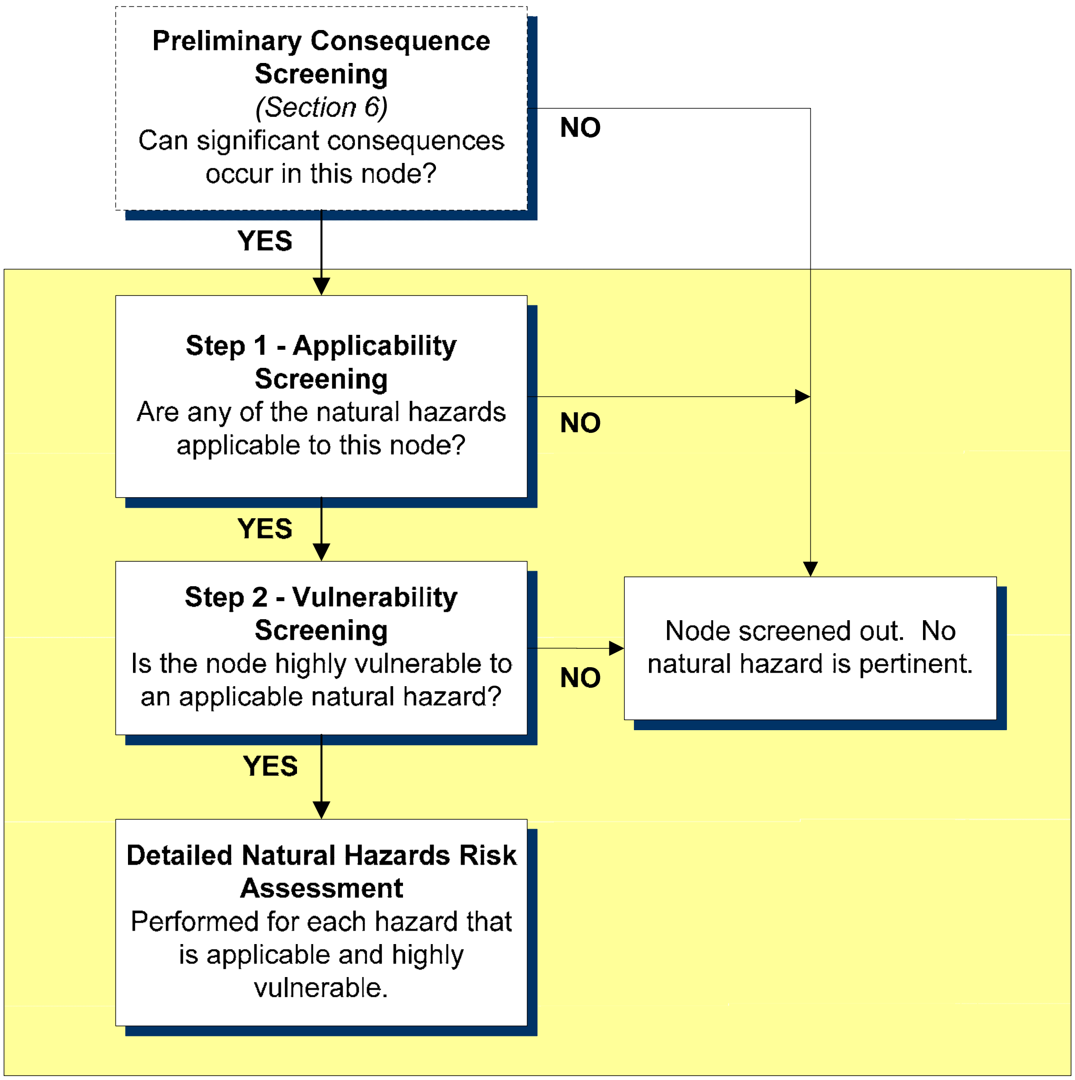

Figure 8-1 Natural Hazard Risk Assessment Process

8.1.4 Natural Hazards Assessment Data Sources

Specific data sets will be required to conduct both the natural hazards screening portion of the natural hazards risk assessment and any detailed assessment that follows. A combination of data sources will be utilized which include publicly available federal and state agency data, design codes and standards, subject matter experts, academic sources, and information from the infrastructure owners/operators (if available). The information that is collected will be used to supplement the ALA guidelines[2] vulnerability screening criteria, as well as to provide input to the detailed natural hazard evaluation of screened nodes and hazards. More specifics on the data required for the natural hazards assessment are included in Appendix K.

8.1.4.1 Publicly Available Data Sources and Literature Search

A variety of public sources will supply data in support of the natural hazards assessment. Literature surveys on these sources will be performed with a focus on targeting potential impacts of hazards on the infrastructure. Several federal and state agencies have active ongoing programs to identify, research, and manage natural hazard risks. The natural hazards assessment will examine public sources of hazards information from the following agencies:

- U.S. Geological Survey (USGS)
- U.S. Minerals Management Service (MMS)
- U.S. Bureau of Land Management (BLM)
- U.S. Army Corps of Engineers Cold Regions Research and Engineering Laboratory (USACE-CRREL)
- National Oceanic and Atmospheric Administration (NOAA)
- U.S. Federal Emergency Management Agency (FEMA)
- Alaska Department of Natural Resources Division of Geological & Geophysical Surveys (DGGS)
- Other agencies as applicable

These federal and state agencies are expected to provide significant information on the spatial distribution, frequency, and possible severity of natural hazards events. This information will provide a publicly available source of data to screen infrastructure nodes for natural hazards risks, and will provide initial inputs for the detailed natural hazards risk assessment.

Other potential sources of public information will include design codes and standards, published reports, and research studies on the design basis of existing facilities and components in Alaska's oil and gas infrastructure. Sources for this type of information are expected to include academic research papers on the performance of infrastructure from research institutions, professional societies, and journals such as:

- Multidisciplinary Center for Earthquake Engineering Research (MCEER)
- Pacific Earthquake Engineering Research Center, the University of California
- University of Alaska and Cornell University, among others
- Earthquake Engineering Research Institute Offshore Technology
- Institute of Petroleum Engineers

- Other research institutions, professional societies, and journals as applicable

Interviews with public, academic, and governmental subject matter experts will also be solicited to formulate appropriate supplemental screening criteria for hazards and infrastructure node vulnerability and damage models.

The information collected from these sources will provide a public source of data on the design, construction, and potential performance and vulnerabilities of structures, systems, and components of the oil and gas infrastructure to natural hazards.

Hazard studies, design standards, and other hazard-related data commissioned in the design and upgrade process by the owners/operators of the facilities will be requested to supplement the public resource data collection effort. Site-specific hazard information will be incorporated into the screening and subsequent hazards analyses to the extent that it is available to the project.

8.1.4.2 Historical Hazard Events and Operator Experience Survey

It is well known that Alaska is subject to diverse natural hazards. Historic records of these natural hazard events are limited to the current period of American occupation, supplemented by limited records from the Russian period and some oral history from Native Americans. Much of this recorded history has been limited to the inhabited coastal regions of south-central Alaska. However, the USGS has used paleoseismic field techniques in some areas to investigate prehistoric occurrences of earthquakes, which serve to extend and reconstruct a longer record of Alaskan earthquake history.

In the recent past Alaska experienced the most powerful earthquake ever recorded in North America, the "Good Friday" earthquake and tsunami of 1964. This event occurred prior to the development of most of the current Alaska oil and gas infrastructure. The 1964 earthquake effects on the developed areas of Alaska are still illustrative of local asset performance for similar types of infrastructure. More recently, the Denali earthquake of 2002 directly affected TAPS. According to a summary paper presented at an ASCE conference in August 2003, "The magnitude 7.9 earthquake that occurred in south-central Alaska on November 3, 2002 ruptured a 336-km long segment of the Denali Fault. The epicenter was located about 88 km west of the Trans-Alaska Pipeline, and the rupture propagated to the east across the pipeline right-of-way. The performance of the pipeline was in line with original project design requirements, and there was no crude oil leakage."[35]

Another well known natural event is the Redoubt volcanic eruption, which occurred during a five-month period beginning in December 1989. Mt. Redoubt is in close proximity to infrastructure in the Cook Inlet, and this eruption forced mud flows from Redoubt into the Drift River drainage and caused partial flooding of the Drift River Oil Terminal facility. "Massive block and ash avalanches down the Drift Glacier generated the largest debris flow of the eruption, completely covering the 2-km-wide valley floor and spilling into Cook Inlet. Flood waters entered the oil terminal, as much as 75 cm deep in some buildings, and caused a temporary halt in operations."[36]

In addition to the impacts of these well-known and widespread events, efforts will be made to obtain reports and records of other more localized, less severe, and less well-known natural hazard occurrences that have affected the oil and gas infrastructure. These events, with smaller impacts, can provide knowledge into the lower bound of effects of natural hazards on the infrastructure, as well as identify potentially significant vulnerabilities that may be exhibited by larger and more widespread consequences for more intense future occurrences. Efforts will be made to obtain publicly available documents from state and federal agencies.

The most detailed and comprehensive records of prior natural hazard performance experience may be available only through the facility owners and operators. The project implementation effort would benefit from the opportunity to conduct working sessions with engineering representative of the facilities. These sessions would help provide a more complete understanding of the facilities and basis of their designs, design criteria, and modifications histories. Often natural hazard occurrences that are not catastrophic have limited, if any, historical record. Working interview sessions with facility operations and engineering staff could provide a means to access these "institutional memories" of natural hazards occurrences. Past low intensity events and the problems that resulted can identify the weak links, or components, that could limit operations in more intense future occurrences. Efforts will be made to identify potential sources of such precursor event data and obtain appropriate access and use of these records for this project.

8.1.4.3 Event/Node Specific Data Sources

Event/node specific data needs and data sources pertinent to the natural hazard assessment have been identified and are presented in multiple locations in this report. The following sections of this document provide detailed information on specific data requirements and references.

- Section 8.3.2 contains a description of event-specific data sources and their utility. This description focuses on the 10 classes of natural hazard events and describes hazard and data sources for those events.
- Appendix C provides a table that aligns infrastructure components with data attributes and associated facility specific data.
- Appendix K is a comprehensive listing of natural hazard document references that have been compiled to-date. Additional data sources are expected to be added to this list throughout Phase 2 of the project.

8.1.4.4 Local vs. Regional Data

Natural hazards are characterized as either "local" or "regional" in their effects and extent. Regional hazards affect large areas, such as a state, and can extend for hundreds of miles. Earthquake ground shaking, extreme winds, coastal flooding, and icing are examples of regional hazards. In contrast, local hazards affect small areas and typically can be characterized only by conducting site-specific fieldwork or small scale or micro mapping. Some examples of local hazards are riverine flooding, landslides, earthquake surface fault rupture, soils liquefaction, and settlement.

For the ARA Project, the important distinction between local and regional hazards is that local hazards require site-specific information for facilities, many of which are located in remote areas. This type of accurate and site dependent data is typically gathered by the owners/engineers at the time of construction, during facility expansions and modifications, or when a natural hazards problem is identified and is investigated in some detail. Local site surveys or field studies will not be conducted; however, research will be completed to determine if this information is available from public sources or from owner/operators of the oil and gas facility.

An important consideration when quantifying each natural hazard is the local site intensity. The intensity at the source of a natural hazard (for earthquake, the earthquake fault; for a winter storm, the footprint of temperature and precipitation) is defined for each node in proximity to the event location.

Some hazards, such as large-scale weather events, have large relatively homogenous conditions covering tens to hundreds of square miles. Conversely, local effects for hazards such as earthquake-induced subsidence are highly dependent on site conditions. The identification and determination of local site intensities can result from several factors: soil and slope conditions, proximity to the event, magnitude of the event, and the type of event. For example, a site's soil conditions can change the effects of intensity of ground shaking from a distant earthquake by many factors. Also, the presence of earthquake faults on or near the infrastructure node can dramatically change the earthquake exposure and potential for damage.

Local mapped site information that is available will be used to estimate damage for each hazard based on the intensity of the event.

8.2 Natural Hazard Screening

In order to focus the assessment on node/hazard event combinations that could present potentially high-risk events, a two-step approach will be used to screen and evaluate nodes for natural hazards. This is displayed visually in Figure 8-3 in Section 8.3.1.

The natural hazard screening process begins after preliminary consequence screening is complete, as described in Section 6. Only those infrastructure nodes that have the potential to experience significant consequences as determined in the preliminary consequence based screening will be subject to the further natural hazards screening process.

The natural hazards screening will eliminate infrastructure nodes from further evaluation where it is found that:

- There are no significant natural hazards that could affect the node, based on the Step 1 - Applicability Screening, or
- The node is not susceptible to significant damage or failure if subjected to the hazard(s), based on Step 2 – Vulnerability Screening.

This is visually displayed in Figure 8-2 below.

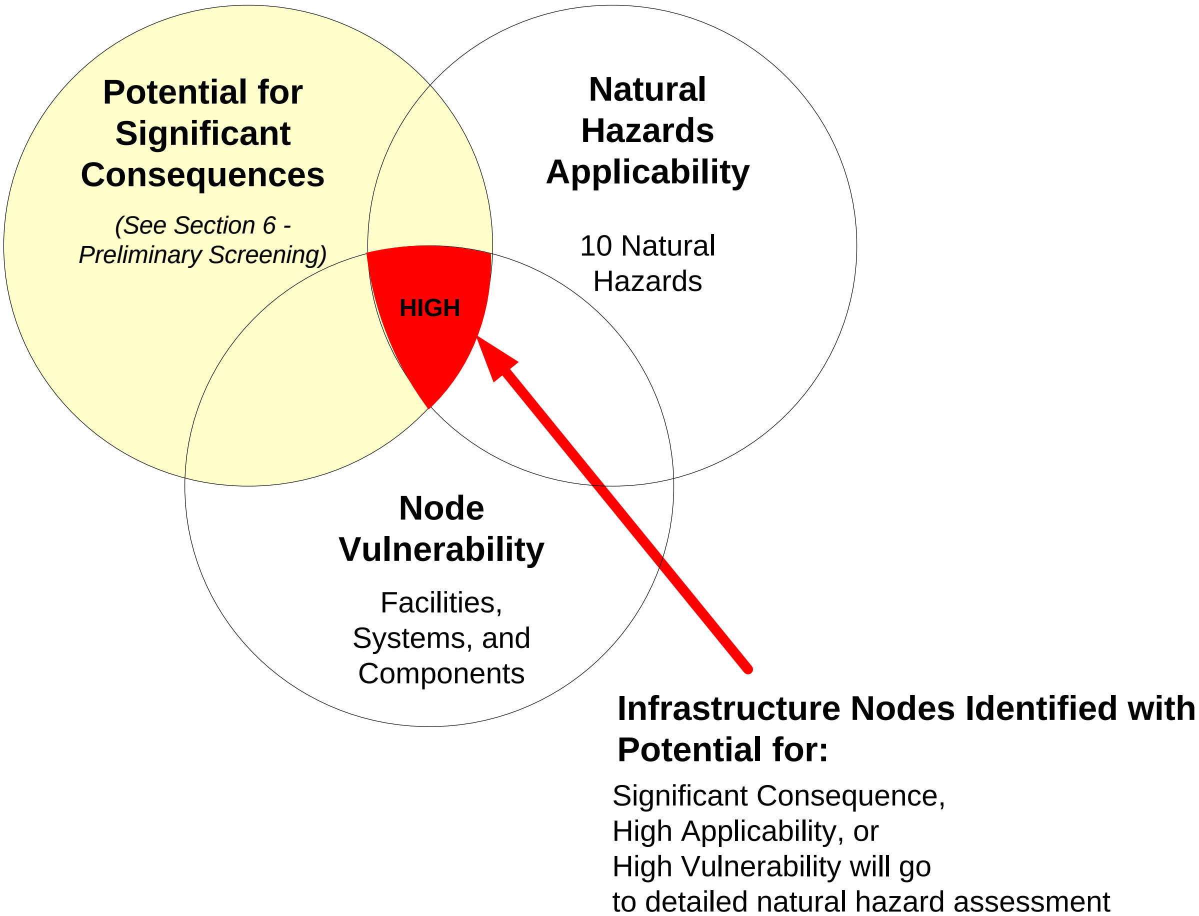

Figure 8-2 Consequence and Natural Hazards Screening

This natural hazards screening approach has several advantages:

- Facilities, systems, and components that are clearly not at risk can be screened out early.
- Results from the initial screening provide risk information to prioritize and allocate resources for a more detailed assessment, where necessary.
- The information or data needed for the detailed assessment is likely to be developed or discovered during screening.

The natural hazard screening is a qualitative evaluation that will reduce the number of nodes requiring further detailed natural hazard assessment. The higher the data quality available for screening, the more precise the screening can become and the more efficient the tool will be for focusing the risk assessment.

8.2.1 Step 1 – Applicability Assessment

Due to the broad geographic scope of the Alaska oil and gas infrastructure, a specific infrastructure node may be subjected to some hazards, but not necessarily to all of the hazards under consideration. It is well known that exposure in Alaska to natural hazards is not geographically uniform across the state. For example, earthquake and volcano exposures of the south central portions of the state are significantly greater than in the northern portions of the state. Recognizing this non-homogenous distribution of natural hazards, Step 1 of the natural hazard screening will compare each of the ten classes of natural hazards described in Section 8.3.2, with each infrastructure node to determine if the hazard has a high, medium, or low potential to occur in that geographic region.

Analyzing regional hazards can be accomplished using hazard maps that cover large areas to characterize the hazard levels for earthquakes, severe wind, ice storms, and other regional hazards. It should be noted that the information on such regional maps is approximate and can be misleading when considering the presence of local hazards. The scale may cause the entire region to be classified according to the severity of the single instance of the local hazard. For example, it is common to screen for landslides based on landform slope gradient. A large area that contains a few locations with steep slopes may be classified on a low resolution map as high risk for landslides, even though a relatively small portion of the land area is situated on steep slopes. It should be recognized that local hazards have site-specific aspects that must be determined from high-quality data associated with each node. For the initial natural hazard applicability screening, the presence of local hazards within a large mapped area can result in classifying an entire area as high hazard.

The result of the Step 1 applicability screening will be a matrix organized by infrastructure node that indicates which of the ten natural hazard classes has the potential to have adverse impacts on the node. The matrix below is adapted from ALA guidelines[2] and reflects typical applicability screening criteria. A similar table customized for the ARA Project will be used to designate hazards as having high, medium, or low applicability for each node. Hazard/node combinations with a high score will require further natural hazard assessment in Step 2.

Table 8-2 Criteria for Natural Hazards Applicability Screening

Hazard Level	Earth-quake[2]	Landslide	Wind	Icing[3]	Flooding[4]	Fire[1]	Ground Movements (frost heave, settlement)[1]	Avalanche[1]	Volcano[1]	Severe Currents[1]	Coastal Erosion[1]
Low	Peak ground acceleration (PGA) < 0.15g	Low incidence	Not high or medium	<0.25 in.	Q3 data not available for the county	NFDRS or CFDRS fire risk rank (to be established)	USGS sporadic permafrost region	Slope < 20°	No historically active volcano within 100 miles of facility		
Medium	0.15g < PGA <0.5 g	Moderate incidence or moderate susceptibility/ low incidence	Windspeed > 90 mph, but < 120 mph	> 0.25 in. and < 1.0 in.	Q3 data not available for the county	NFDRS or CFDRS fire risk rank (to be established)	USGS continuous and discontinuous permafrost region	Slope > 20° but < 30°	Historically active volcano within 50 miles of facility		
High	PGA > 0.5 g	High incidence or high susceptibility/ moderate incidence, or high susceptibility /low incidence	Windspeed >120 mph	> 1.0 in.	Q3 data not available for the county	NFDRS or CFDRS fire risk rank (to be established)	USGS continuous and discontinuous permafrost region	Slope > 30°	Historically active volcano within 25 miles of facility	**No screening criteria currently established**	Proximity to coast

Note 1: Hazards and Oil & Gas Infrastructure outside the ALA Guideline

Note 2: In establishing the earthquake hazard, the ALA Guideline uses earthquake hazard maps depicting ground motions with a probability of exceedance equal to two percent in 50 years.

Note 3: In establishing the icing hazard, the ALA Guideline uses ASCE 7, Minimum Design Loads for Buildings and Other Structures. These maps represent 50-year mean recurrence interval uniform ice thicknesses due to freezing rain.

Note 4: The digital Q3 Flood Data published by FEMA are designed to provide guidance and a general proximity of the location of Special Flood Hazard Areas. The digital Q3 Flood Data are not expected to cover a large extent of Alaska's infrastructure. Site-specific flood sources will be required

8.2.2 Step 2 – Vulnerability Assessment

Given that a specific infrastructure node is subject to a hazard, certain component types within that node may be vulnerable to damage from some hazards, but not others. Step 2 of the natural hazards screening will analyze the nodes that have high exposure to natural hazards or have highly vulnerable components. This will be accomplished using the ALA guidelines[2] as a foundation, which bases vulnerability of key oil and natural gas pipeline system components on the judgment of experienced practitioners and qualitative information. ALA guidelines[2] provide screening criteria for the regional scale natural hazards events that have been associated with major past damage to oil and gas infrastructure, such as earthquakes, ice and winter weather, tsunamis, and others. Wind and icing have smaller direct effects on oil and gas pipelines, but can be a significant disruption to electric power systems that may feed that infrastructure. The ALA guidelines[2] do not provide screening criteria for some of the other more localized natural hazard phenomena such as permafrost, avalanches, and severe currents. These criteria will be developed as part of the natural hazards screening process.

Table 8-3 provides an example of vulnerability screening criteria consistent with the ALA guidelines[2] in terms of typical components and noncritical components specific to each of the natural hazards being considered. Similar criteria will be developed and applied in Step 2 of the natural hazards screening process for this project. Special circumstances may exist that would cause a particular infrastructure node to be more or less vulnerable than indicated in Table 8-3.

Table 8-3 Criteria for Node Vulnerability Screening

HAZARDS	DEGREE OF VULNERABILITY													
Natural Hazards	**Transmission Pipeline**	**Pump Stations**	**Compressor Stations**	**Production and Processing Facilities**	**Storage Tanks**	**Support and Control Systems**	**Maintenance and Operations Buildings and Equipment**	**Pressure Regulating/Metering Stations**	**Distribution Pipelines**	**Service Lines or Connections**	**Offshore Production Facilities[1]**	**Submarine Pipelines[1]**	**Wells[1]**	**Marine Facilities[1]**
Earthquake Shaking	L	M	M	M	H	M	H	L	L	M	L	H	L	H
Earthquake Permanent Ground Deformations (fault rupture, liquefaction, landslide settlement)	H	-	-	-	L	-	-	L	H	M	M	H	M	H
Ground Movements (landslide, frost heave, settlement)	H	-	-	-	L	-	-	L	H	M	M	H	M	H
Flooding (riverine, storm surge, tsunami and seiche)	L	H	H	H	M	H	H	H	L	M	H	L	H	H
Wind	L	-	-	-	-	L	L	-	-	-	H	L	-	H
Icing	L	-	-	-	-	-	-	-	L	-	H	L	-	H

HAZARDS	DEGREE OF VULNERABILITY													
Natural Hazards	Transmission Pipeline	Pump Stations	Compressor Stations	Production and Processing Facilities	Storage Tanks	Support and Control Systems	Maintenance and Operations Buildings and Equipment	Pressure Regulating/Metering Stations	Distribution Pipelines	Service Lines or Connections	Offshore Production Facilities[1]	Submarine Pipelines[1]	Wells[1]	Marine Facilities[1]
Collateral Hazard: Fire	M	H	H	H	H	M	L	L	L	M	-	-	-	-
Collateral Hazard: Nearby Collapse	-	L	L	L	-	L	L	L	M	L	-	-	-	-
Collateral Hazard: Dam Inundation	L	H	H	H	M	H	H	H	L	M	-	-	-	-
Avalanche[1]	H	-	-	-	L	-	-	L	H	M	-	-	-	H
Volcano[1]	H	H	H	H	H	H	H	H	H	M	H	L	H	H
Severe Currents/Coastal Erosion[1]	-	-	-	-	-	-	-	-	-	-	H	H	H	M

Note 1: Hazards and Oil & Gas Infrastructure outside the ALA Guideline.

Table 8-3 identifies the general degree to which oil and natural gas pipeline system components are potentially vulnerable to the hazards. The entries are in the form of an unqualified "H," "M," or "L" (high, moderate, or low). Where a component is located below the ground, it tends to be vulnerable to permanent ground movement hazards (surface fault rupture, liquefaction, landslide, frost heave, and settlement). Aboveground components will be more affected by earthquake ground shaking, flooding, wind, icing, and other collateral hazards (blast, fire, dam inundation, and collapses of nearby structures). If the component being evaluated has not been designed for the hazard under consideration it may be more susceptible to damage. Where the original component design basis is not known and is relatively old, it may not have been accounted for in relation to some hazards. Detailed evaluation may be indicated for older facilities where design data is not available. Criteria can be established to incorporate these more detailed vulnerabilities if data is available to support it. The absence of an entry in a particular cell indicates that the corresponding component is not expected to be susceptible to damage or disruption regardless of hazard level.

The ALA guidelines screening criteria and other criteria presented are based on past observations of different types of structures, systems, and equipment having a range of vulnerabilities to hazards. For example, some types of structures and components have long established histories of good performance in earthquakes, while others have exhibited much lower thresholds before damage occurs. Some types of steel-framed structures, when designed to building code provisions, have shown excellent performance. On the other hand, components of electrical power systems like transformers and circuit breakers are often damaged even at low ground motions. The supplemental screening criteria developed will take into consideration the varying types of structures, system, and equipment that may be present at the various nodes and will establish screening criteria that consider an appropriate lower bound for screening of each hazard. In this way, each hazard will have threshold criteria for severity established that reflect the representative types of structures and systems.

The outcome of the Step 2 vulnerability assessment will be a matrix reflecting each node type included in the scope of the ARA Project and its vulnerability with respect to each of the ten applicable classes of natural hazards described in Section 8.1.1. Using these criteria, only node/hazard combinations that rank as high vulnerability from the preliminary screening would be included in the detailed natural hazard assessment.

8.3 Detailed Natural Hazards Risk Assessment

A more detailed evaluation is indicated for those nodes found to have a potential for significant consequence(s) during preliminary screening, and at high exposure for specific natural hazard applicability and vulnerability during natural hazard screening. Further quantification of the risks will allow identification of the features of the infrastructure that govern the risks and opportunities for improvement. This more detailed natural hazards assessment will examine the identified hazards for each node and will quantify, to the degree supported by available data, the likelihood and the associated severity of events with respect to reliability, the environment, and safety of industry workers and the public. Attributes of both the hazards and the infrastructure nodes will be scored to allow ranking and quantification of the consequences of each hazard for each node.

8.3.1 Detailed Natural Hazards Assessment Procedure

The detailed natural hazards assessment will use a systematic procedure for assessing the performance of oil and gas nodes subject to natural hazards. This assessment will be based on the methods recommended in the ALA guidelines[2], which generally follow current practice in the discipline of natural hazards risk assessment (refer to Section 8.1.2). This current practice includes analysis steps common to most natural hazards risk assessment, including identifying and quantifying hazards, assessing damage states of nodes, considering existing mitigation measures, and estimating natural hazard risk. This methodology is described in the following sections and is displayed visually in Figure 8-3.

NATURAL HAZARDS SCREENING RESULTS

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Identify and Quantify Natural Hazards

- Use data from sources such as maps, site-specific information from operators, historical information, scientific observation, or instrumental data collection to model and quantify intensity and frequency of hazards
- Qualitatively discuss hazards that are not quantifiable through available data

↓

Identify and Quantify Damage States of Nodes

- Apply vulnerability relationships to determine total node damage status
- Establish node vulnerability based on engineering analysis procedures, past performance of systems in natural hazards events, and engineering judgment
- Apply node vulnerability information to estimate hazard scenario frequency

↓

Consider Existing Mitigation Measures

- Evaluate the influence of emergency response/recovery and other hard and soft mitigation measures on event consequences
- Assess consequences of natural event on response resources and infrastructure support for response (roads, electric power, etc.)
- Estimate natural hazard scenario consequences (consistent with operational events consequence methods)

↓

Estimate Infrastructure Natural Hazard Risks

- Estimate risks using hazard frequency, local intensity, component vulnerability and existing mitigation
- Summarize integrated results by consequence type
- Identify natural hazards that present high risks
- Identify major risk contributors and other contributing factors

↓

COMBINE WITH OPERATIONAL HAZARDS RISK RESULTS

Figure 8-3 Detailed Natural Hazard Risk Assessment Process Steps

Implementation of this process will result in the definition of natural hazard scenarios and an estimation of the frequency and consequence for those scenarios that allow natural hazards risks to be included in the project risk profile for the Alaska oil and gas infrastructure. The ALA guidelines describe this continuum of detail as Levels 1, 2, and 3 (where Level 3 is the highest level of detail and Level 1 is the lowest level of detail). Due to the large number of different hazards to be considered and the physical scope of the infrastructure to be considered, the general approach will be to implement the Level 1 approaches recommended by the ALA guidelines and comparable approaches (where practical) for infrastructure items not covered by those guidelines.

8.3.1.1 Identify and Quantify Natural Hazards

Once the nodes at risk have been identified through the screening process, the risk assessment methodology follows a standard procedure, regardless of the type of natural hazard being investigated (e.g., earthquake, wind storms, flood). The first step in this procedure is modeling the hazard phenomenon based on historical and scientific information.

As noted in Section 8.1.2, the ALA guidelines will be used to conduct this modeling. Hazards maps and detailed site-specific information will be used to the extent that it is available to the project.

Section 8.3.2 provides a more detailed description of data sources needed to conduct the detailed natural hazard assessment for each of the 10 natural hazards. For some of the 10 natural hazard classes, methods are not currently available to predict recurrence frequencies or event intensities in a manner to allow quantification of the risk they present. These hazards include 1) volcanic eruptions, 2) tsunamis, 3) severe currents, 4) coastal erosion, 5) forest fires, and 6) permafrost thawing. Therefore, all of the hazards to be investigated in this project will not necessarily allow the same level of scientific rigor in the estimation of the intensity of future events or the likelihood of occurrence. In some cases, the assessment may only include a qualitative discussion of the issues associated with a specific hazard.

8.3.1.2 Identify and Quantify Damage States

After the intensity of the hazard (e.g., shaking intensity, icing) is estimated at each site, the damage to the node can be assessed and quantified using vulnerability models. As discussed in Section 8.3.3, a Level 1 approach will be followed. The level of detail achieved when conducting damage assessments is flexible, and dependent on the amount of information that is available on the physical characteristics of the assets in the node (i.e., appropriate inventory information on structures, systems and equipment). The availability of this information is expected to vary, depending on the type of asset, the owner/operator of the node, and other factors. Section 8.3.2 provides additional detailed information on data sources for conducting damage assessments for each of the 10 natural hazard classes.

8.3.1.3 Consider Existing Mitigation Measures

Emergency planning and other hard and soft mitigation measures can have a major impact on the consequences that result from natural hazards damage. Maintaining or rapidly repairing infrastructure and communication systems is critical following a hazard event. Disruption to critical services such as roads, rail service, businesses, and lifelines can seriously affect a community’s ability to respond to an event such as a large-scale earthquake. Many key resources that can be vulnerable and damaged such as water sources, water and sewer lines, electric, gas and phone utilities, fire, and evacuation support can contribute to the length of repair and recovery times. The extent of hazard mitigation plans and emergency response resources all play a major role in the ultimate impact of hazard events. Existing mitigation measures will be considered with regard to their influence on ultimate event consequence using an approach consistent with the consequence assessment discussion in Section 7 of this report.

8.3.1.4 Estimate Infrastructure Natural Hazard Risks

The final step in the detailed natural hazards assessment is to estimate the types and extent of damage to the facilities, systems and components for each of the hazards. The individual damage estimates consider the hazard frequency, local intensity, vulnerability of components and existing mitigation. For events where damage can extend to multiple facilities, the total risk will be summarized for the hazard. These risk estimates, along with the event frequency will be provided as input to the project damage assessment model to quantify the reliability, environment and safety consequence of the event in a manner that is consistent with the operational events which are being considered. Each of the event consequences and associated frequencies will be captured in the database as significant events.

8.3.2 Individual Natural Hazards

This section breaks down each of the 10 natural hazard classes under consideration, and provides a description of the data sources appropriate for use in evaluating their likelihood and severity. Data sources fall into two general categories.

- Hazard Data Sources – information specific to the hazard being evaluated.
- Damage Model Sources – information specific to damage of infrastructure from these hazards.

Potential data sources specific to infrastructure nodes for each class of natural hazard are presented in Appendix K of this report. It provides a table reflecting node type, data attributes, and associated data sources.

8.3.2.1 Earthquakes and Tsunamis

<u>Hazard Data Sources</u>

Earthquake hazards in Alaska have been studied in great detail for at least four decades following the 1964 Good Friday earthquake. Historic information, including frequency, location, and magnitude of past events, has been assembled, along with scientific information, by the USGS, the State of Alaska Division of Geological & Geophysical Surveys (DGGS), academics, and others.

Publicly available earthquake data sources for Alaska are:

Wesson, R.L., Boyd, O.S., Mueller, C.S., Bufe, C.G., Frankel, A.D., and Petersen, M.D., *Revision of Time-Independent Probabilistic Seismic Hazard Maps for Alaska,* U.S. Department of the Interior U.S. Geological Survey, Open-File Report 2007–1043.

Applied Technology Council (ATC-1): Earthquake Damage Evaluation Data for California. Developed under a contract with the Federal Emergency Management Agency (FEMA), 1985.

American Society of Civil Engineers, *Minimum Design Loads for Buildings and Other Structures*, ASCE Standard 7.

Damage Model Sources

A Level 1 damage assessment will be performed based on the ALA Guidelines as discussed in Section 8.1.2. Original design criteria will be evaluated and taken into consideration during the assessment.

8.3.2.2 Volcanoes

Alaska has over 90 active volcanoes. Most of these volcanoes are located along the Aleutian Arc, well away from concentrations of oil and gas infrastructure. The largest concentration of volcanoes, in proximity to oil and gas infrastructure, is located on the western side of the Cook Inlet and includes six volcanoes: Augustine, Iliamna, Redoubt, Double Glacier, Spurr, and Hayes. The most recent volcanic eruption, Redoubt, occurred in 1989-90. There have been six prior eruptions since 1778, and similar eruptions are expected in the future.

The primary perils experienced from eruptions include ash clouds and fallout, and lahars, which are the result of hot lava, snow, and ice interacting to form fast-moving slurries of ash, mud, rock, and debris. Other types of volcanic materials expelled result in pyroclastic flow of hot volcanic material mixed with debris moving downhill at rapid speeds. Other volcanic effects include direct blasts. The Redoubt eruption provides the most recent and detailed account of the hazards faced by infrastructure in the Cook Inlet. During the Redoubt eruption, lahar flows spilled down the Drift River Drainage into the Cook Inlet and caused flood waters to partially inundate the Drift River Marine Terminal.

Hazard Data Sources

The primary research institutions involved in study and reporting on Alaskan volcanic activity include:

- The Alaska Volcano Observatory (AVO), United States Geological Survey (USGS)
- The Global Volcanism Program, Smithsonian Institution
- The Geophysical Institute of the University of Alaska Fairbanks (UAFGI)
- State of Alaska Division of Geological and Geophysical Surveys (ADGGS)

The AVO monitors and performs scientific investigations to assess the nature and likelihood of volcanic activity. They also assess volcanic hazards, including types of events, their effects, and areas at risk, and provide warnings of impending dangerous activity. The AVO provides the highest quality information available on Alaska's volcanoes. However, the state of scientific knowledge is not as well advanced as some other areas of earth sciences, such as earthquake hazard development where models are available to estimate earthquake frequency and severity. Volcanic hazards are typically portrayed in static geologic maps of the distribution of ash and debris from past eruptions. This information is useful for reconstructing the size of past eruptions and for modeling eruption hazard scenarios. Topography and landforms in the immediate vicinity of the edifice guide judgment on the relative levels and locations of avalanche and lahar hazards. Prevailing wind direction and storm tracks, combined with storm frequency, guide judgment on the aerial dispersal of ash and eruptive debris.

Damage Model Sources

Some information on exposures of the oil and gas infrastructure is available from the AVO. Evaluations will be based on issues and nodes identified in the consequence and hazard screenings.

Public literature on volcano hazards and damage will be reviewed. Interviews with public, academic, and governmental subject matter experts will be also be solicited to formulate a damage model for identified issues. Site specific information is essential to understand the planning and mitigation efforts that have been implemented by the owners/operators of infrastructure that could be exposed to volcanic eruptions.

8.3.2.3 Coastal Erosion

Coastal erosion may stem from a variety of causes. Traditionally, severe coastal erosion has been associated primarily with storm events from which the recurrence frequency and hazard severity could be implied. More recently, quasi-continuous coastal erosion is beginning to be understood in terms of climate change with associated loss of ice-cover and permafrost in arctic regions. The simultaneous slow rise in sea level is viewed as exacerbating the hazard. The U.S. Army Corps of Engineers has active erosion control projects in Alaska coastal communities and tribal lands, and the USGS has been conducting research on coastal erosion rates in arctic Alaska related to climate change. Erosion rate data from these initiatives will be investigated for developing models of this phenomenon in coastal areas of oil and gas infrastructure.

Subsidence is a major hazard that may be associated with coastal erosion. Subsidence can be caused for a variety of reasons including:

- Underground fluid withdrawal
- Earthquake induced (Good Friday earthquake of 1964 is a classic example)
- Drainage of organic soils
- Hydrocompaction
- Thaw induced subsidence
- Natural compaction

Risk assessment methods for this hazard class will be customized depending on identification of site-specific instances of subsidence and coastal erosion that have potentially significant consequences.

<u>Hazard Data Sources</u>

Several agencies have information related to coastal erosion and subsidence in Alaska including the USGS, Bureau of Mines, the U.S. Army Corps of Engineers, the Bureau of Land Management, the Alaska Department of Natural Resources Division of Coastal & Ocean Management, the University of Alaska Fairbanks, and the U.S. Agricultural Research Service. (Required data sources are to be determined based on issues and nodes identified.)

Mars, J.C., Houseknecht, D.W., *Quantitative remote sensing study indicates doubling of coastal erosion rate in past 50 yr along a segment of the Arctic coast of Alaska*, U.S. Geological Survey, MS 954, National Center, Reston, Virginia 20192, USA.

U.S. Army Corps of Engineers: *Alaska Villages Erosion Technical Assistance (AVETA); Alaska Baseline Erosion Assessment Study; Long-Term Alaska Wind, Wave and Surge Climatology Study.*

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Damage Model Sources

Much of the Alaska oil and gas infrastructure is sited in remote locations. Site-specific information is essential to understand the owners/operators past operation experience with regard to subsidence and coastal erosion. The oil and gas infrastructure has had several decades of operational experience for wells, gathering lines, production facilities, pipelines, and terminals. Available operator experience data on subsidence and coastal erosion problems will be reviewed and will provide the basis for identifying potential vulnerabilities.

Site-specific information is also essential to understand the history and mitigation efforts that have been implemented by the owners/operators of nodes that could be exposed to subsidence and coastal erosion.

Public literature on coastal erosion hazards and damage will be reviewed. Interviews with public, academic, and governmental subject matter experts will also be solicited to formulate a damage model for identified issues.

Risk evaluations will be based on the 1) issues and nodes identified in the consequence and hazard screenings and 2) a Level 1 assessment based on the ALA guidelines.[2]

8.3.2.4 Permafrost Thaw

Design for permafrost conditions is a standard part of arctic engineering. The highest profile permafrost engineering project in the Alaska oil and gas industry is associated with TAPS. Permafrost was considered in the original design of both aboveground vertical support members (VSMs) and buried segments. Other portions of the oil and gas infrastructure beyond TAPS will also be screened and reviewed to identify issues with permafrost that may present potential adverse consequences.

Hazard Data Sources

U.S. Arctic Research Commission Permafrost Task Force Report, *Climate Change, Permafrost, and Impacts on Civil Infrastructure,* December 2003, Special Report 01-03.

US Geologic Survey (USGS), *Permafrost database, as modified from O.J. Ferrians.*

Brown, J., and C. Haggerty, *Permafrost digital databases. Eos, Transactions,* American Geophysical Union, 79, 634, (1998).

Damage Model Sources

Site-specific information is essential to understand the owners/operators past operation experience with permafrost effects on structure supports. The oil and gas infrastructure has had several decades of operational experience. Available operator experience data and permafrost problems will be reviewed and will provide the basis for identification of potential permafrost vulnerabilities.

Site specific information is also essential to understand the history and mitigation efforts that have been implemented by the owners/operators of nodes that could be exposed to permafrost.

The prediction of the time, rate, magnitude, and place of permafrost melting due to climate change is outside the scope of this risk assessment.

Evaluations will be based on the 1) issues and nodes identified in the consequence and hazard screenings and 2) a Level 1 assessment based on the methods recommended in the ALA guidelines.

8.3.2.5 Severe Storms

Hazard Data Sources

Alaskan weather has been studied for many decades by government agencies and atmospheric scientists. Extensive sources of raw weather data, as well as processed data suitable for engineering design and risk assessment, are available from various sources. Publicly available data sources for Alaska include:

- National Climatic Data Center Datasets (i.e., the Automated Surface Observing System and Automated Weather Observation System)
- *ASCE Standard 7 Minimum Design Loads for Buildings and Other Structures.*
- U.S. Army Corps of Engineers CREEL, *Ice Accretion in Freezing Rain.*
- American Lifeline Alliance, *Extreme Ice Thicknesses from Freezing Rain.*

Damage Model Sources

Strong gusting wind can threaten both onshore and offshore structures. Onshore Alaskan structures are typically designed to Alaskan building code standards, which take these extreme wind exposures into account.

Damage assessment will be performed based on the original design criteria, structure performance, and hazard intensities of wind, wave, ice, and currents. Also, consideration will be given to damage to outside power, control, and other utilities. Severe weather impacts due to these causes may be frequent and extend over large geographic areas.

Severe weather in Alaska occurs at a high frequency. It is likely that vulnerabilities experienced by infrastructure nodes as a result of severe storms have been observed over time. As a result, historical event reports of severe storm damage may provide the most valuable information on node-specific vulnerabilities. Many of these events are likely not the most extreme that could occur, but the damage that has been experienced could provide a reliable indicator of where damage may occur in more intense, but less likely, future events.

Note: *In general, low temperature due to weather conditions will be considered for its effect on equipment failure frequency in the operational hazards assessment. In contrast, severe weather as a natural hazard will be used to examine potential risks due to periodic severe conditions associated with storms rather than severe temperatures that occur most years.*

Evaluations will be based on issues and nodes identified in the consequence and hazard screenings and a Level 1 assessment based on the methods recommended in the ALA guidelines.

It is anticipated that most of the Cook Inlet production platform structures were designed in the 1960s using pre-*American Petroleum Institute Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms (RP-2A)* design criteria. These offshore structures were likely designed to either owner-specified criteria, which may be unique to the node, or based on architect engineer practice at the time of the design. Many of these older nodes may have been reevaluated to newer criteria and it is likely that all have been subject to some degree of modifications over their in-service life.

To evaluate vulnerabilities of offshore production platforms, some basic design data are required. The basic configurations of the platforms will be used to place the platforms into groupings with similar performance. The minimum platform specific data set would include age, location, water depth, and condition. Also required are general configuration drawings that show air gap design, number of legs, configuration, and design criteria (if available). Currently, it is unknown if this information will be available for use on this project from state or federal sources. Some information is available for some platforms in the open literature; however, much of it is old and may not reflect the current condition of the structures.

Publicly available sources of design information and criteria include:

Visser, Robert C. *Platform Information, Cook Inlet, Alaska, First Ed.* Belmar Engineering.

Bea, Robert G., *Earthquake Criteria for Platforms, in the Gulf of Alaska,* Shell Oil Company.

Wiggins, John H., *Seismic Risk Analysis for Offshore Platforms in the Gulf of Alaska.*

Bea, R.G., *Requalification of a Platform in Cook Inlet, Alaska.*

Visser, R.C., *Reassessment of Platforms in Cook Inlet, Alaska*.

8.3.2.6 Floods

The Federal Interagency Floodplain Management Task Force differentiates several flood types and phenomenology including:

- Riverine flooding
- Local drainage or high groundwater levels
- Fluctuating lake levels
- Storm surges
- Debris flows
- Regional flooding
- Coastal flooding and
- Subsidence

Riverine floods, also categorized as overflow from river channels, flash floods, alluvial fan floods, and ice jam floods, are the most prevalent type of flooding in the United States. Stakeholder outreach sessions identified instances of riverine flooding affecting pipeline supports and debris flows. The initial hazard screening and data collection process will identify the nodes, locations, and types of flooding hazards that may have significant consequences to address in more detail.

Hazard Data Sources

Alaska, due to its size and sparse population, has been behind the continental U.S. in the development of comprehensive coverage and sources of hydrographic data. Various agencies have responsibilities for flood plain management, data collection, and monitoring covering portions of the state. These include National Weather Service, USGS, U.S. Bureau of Land Management, U.S. Army Corps of Engineers, and others.

The USGS, in conjunction with the Environmental Protection Agency (EPA), is developing a National Hydrography Dataset (NHD) for the entire country, including Alaska. The NHD has been endorsed by the Alaska Geographic Data Committee (AGDC) and will act as the data model for Alaska for the long-term use and data maintenance of hydrologic information.

It is unlikely that a single data source will be available that can provide comprehensive flood data to evaluate all of the oil and gas infrastructure sites of interest. The highest quality, and in some cases the only, data that may be readily available are from the owner/operator design engineering, hazard studies, and operation documentation of their nodes.

Damage Model Sources

Site-specific information is essential to understand the owners/operators past operation experience with the nodes. The oil and gas infrastructure has had several decades of operational experience for wells, gathering lines, production facilities, pipelines, and terminals. Flood-related data and incidents from owners/operators will be reviewed, where available, and will provide the basis for identification of past flood vulnerabilities.

Evaluations will be based on the 1) issues and nodes identified in the consequence and hazard screenings and 2) a Level 1 assessment based on the methods recommended in the ALA guidelines.

8.3.2.7 Severe Currents

There are limited numbers of oil and gas facilities that have coastal siting. These include North Slope production facilities, submarine pipelines and production platforms in the Cook Inlet, the Valdez Marine Terminal, and the Drift River Marine Terminal.

In the Cook Inlet, the Drift River Marine Terminal, submarine pipelines, and offshore production nodes are exposed to the well-known Cook Inlet tidal conditions. The Drift River Marine Terminal is exposed to a spring tidal range of -1.5 meters to +9.45 meters. These conditions are accompanied by tidal currents of up to 7.5 knots. Anecdotal reports of currents during large tides in Cook Inlet range as high as 8 to 9 knots. To assess the vulnerability of Cook Inlet nodes to these conditions, access will be required to site-specific data on past historical performance and documents related to the design of specific structures to assess the risk from underwater currents.

Turbidity currents, which are a dense sediment-laden current of water that moves rapidly down-slope, are a potential hazard to offshore oil and gas infrastructure. The flow is self-perpetuating through increasing speed as it travels down-slope, which serves to entrain additional sediment that adds to the flow density and speed. Such flows usually only terminate when they reach the flat abyssal plane. Turbidity flows are bottom-seeking and follow canyons and channels along steep bathymetric slopes, usually along the continental shelf slope-break. They are many times triggered by earthquake shaking, submarine landslides, and storm waves where thick sediment has accumulated on overly steep slopes. Offshore investigations have recognized turbidity flow deposits in the Gulf of Alaska abyssal plain. However, frequency data are lacking. One method for assessing this hazard is through scenario models if any offshore oil and gas infrastructure is found to be in proximity to sources of this hazard.

The National Oceanic and Atmospheric Administration (NOAA)/National Ocean Service's (NOS's) Center for Operational Oceanographic Products and Services (CO-OPS) manages the National Current Observation Program (NCOP) to collect, analyze, and distribute observations and predictions of currents. NCOP conducted tidal current surveys in Cook Inlet from 2002 to 2004, collecting current meter time series data at selected stations in support of CO-OPS navigational products and the U.S. Army Corps of Engineers' hydrographic models. The work was completed with the assistance of charted vessels, the Kachemak Bay Research Reserve, the Cook Inlet Regional Citizens Advisory Council, and the United States Coast Guard. NOAA's plans are to use the new information collected on currents from these stations to validate or update NOAA's tidal current tables and provide the basis for new products and understanding of the circulation in Cook Inlet. Existing tidal current predictions in Cook Inlet are based on data collected during the 1973-75 survey or older.

Other researchers into the Cook Inlet tidal currents include the University of Alaska, Fairbanks.

Hazard Data Sources

NOAA/ National Current Observation Program (NCOP), *http://tidesandcurrents.noaa.gov/ncop.html.*

United States Coast Guard, *United States Coast Pilot 9, Coast Pilot 9, Pacific and Arctic coasts of Alaska from Cape Spencer to the Beaufort Sea, 26th Edition, 2008.*

Damage Model Sources

Site specific information is essential to understand the owners/operators past operation experience with severe currents, which is expected to include several decades of experience. Operator experience data and severe current problems will be reviewed and will provide the basis for identification of potential vulnerabilities. Nodes may, or may not, have harbor and marine protection features and design basis that are adequate to protect critical components in extreme events.

Site-specific information is essential to understand the history and mitigation efforts that have been implemented by the owners/operators of nodes that could be exposed to underwater currents. Evaluations will be based on issues and nodes identified in the consequence and hazard screenings.

Public literature searches on severe current hazards and damage will be conducted as part of the assessment. Public, academic, and governmental subject matter experts will also be solicited to assist in formulating a damage model for identified issues.

8.3.2.8 Avalanches

Snow avalanche is a type of slope failure that can occur whenever snow is deposited on slopes steeper than about 20 to 30 degrees. Avalanche-prone areas can be delineated with some accuracy because under normal circumstances avalanches tend to run down the same paths year after year. Exceptional weather conditions can produce avalanches that overrun normal path boundaries or create new paths. Avalanche data are not available to estimate frequency and severity of avalanche events on a statewide basis. Frequency and intensity data are site-specific and would need to be obtained from owners/operators at locations where avalanches have occurred over a long period of time. Valdez is the only currently identified node where an avalanche has occurred with significant consequences. The avalanche at Valdez on February 1, 1977, killed one worker at the terminal.

Hazard Data Sources

Publicly available sources of avalanche hazard information and digital elevation maps that show landform slope include:

Hackett, S.W., Santeford, H.S., "Avalanche Zoning in Alaska," *Journal of Glaciology, v26, no. 94, p385.*

National Academy of Science Press, *Snow Avalanche Hazards and Mitigation in the United States, 1990.*

US Geologic Survey (USGS), *National Elevation Data (NED).*

Damage Model Sources

Unlike other forms of slope failure, snow avalanches can build and be triggered many times in a given winter season. Nodes that are subject to avalanche hazards may take some degree of direct avalanche control. Control is ordinarily exercised through structural engineering systems such as snow-sheds or by the artificial release of built-up snow cover.

Public literature on avalanche hazards and damage will be conducted. Interviews with public, academic, and governmental subject matter experts will be also be solicited to formulate a damage model for identified issues.

Nodes that are identified as having avalanche hazards will require evaluation of node-specific avalanche mitigation measures.

8.3.2.9 Forest Fires

Hazard Data Sources

The Canadian Forest Fire Danger Rating System (CFFDRS) has officially been used by the Bureau of Land Management (BLM) in Alaska since 1992. The CFFDRS is comprised chiefly of two major subsystems or modules: The Canadian Forest Fire Weather Index (FWI) System and the Canadian Forest Fire Behavior Prediction (FBP) System.

To assess current fire danger at local levels, the Alaska Fire Service provides vegetation fuel maps converted into a fire fuel model used by wild land fire management agencies. The system is the keystone of interagency fire danger predictions and provides quantification of risk elements critical for daily decisions regarding firefighter resource placement and strategic decisions at local geographical levels.

Appropriate fire risk-rating indices/mapping will be selected, in consultation with Alaska fire officials, prior to establishing the natural hazards screening criteria.

Damage Model Sources

Much of the Alaska oil and gas infrastructure is sited in remote locations. Site-specific information is essential to understand the owners/operators past experience with forest fires. The oil and gas infrastructure has had several decades of operational experience for wells, gathering lines, production facilities, pipelines, and terminals. Operator experience data and forest fire incidents will be reviewed and will provide the basis for identifying past forest fire vulnerabilities.

Forest fire modeling does not allow prediction of the frequency and severity of events. Site-specific information is essential to understand the planning and mitigation efforts that have been implemented by the owners/operators of nodes that could be exposed to forest fires.

Wildfires exist and grow in the presence of adequate fuel and ignition sources. There are other factors such as relative humidity, fuel load, wind speed, and direction as well as terrain and building features that contribute to the fire spread patterns. The specific circumstances of any given forest fire are unique, and fire risk assessment is not a well-developed practice like wind or earthquake simulation. Some of the important factors in fire simulation include:

- Ignition Hazards- accounts for aspects of the physical environment and human environment leading to fire ignitions from all sources (natural and manmade) to spatial annual ignition rates
- Burn/fire Spread- accounts for the effects of the fuel load (including brush and structures) and the temporal effects such as wind speed, wind direction, and seasonal humidity.
- Fire Suppression- accounts for the mitigating effects of water supplies and access to firefighting resources
- Structure Vulnerability- accounts for the differences in the vulnerability as a function of roof type and brush clearance

Public literature on forest fire hazards and damage will be reviewed. Interviews with public, academic, and governmental subject matter experts will also be solicited to formulate a damage model for identified issues. That information, along with any existing site-specific data will be used in assessing the fire risk for potentially high risk scenarios.

8.3.3 Selection of Analysis Level of Detail

The practice of natural hazards analyses of complex industrial nodes has been developed and is performed in industry at many levels of detail. Techniques and methods are well developed and defined in various risk assessment documents and studies. These levels of risk assessment analyses depend on the types and complexity of nodes, as well as the level of prior design and risk assessment documentation available from the owners/operators. In natural hazards risk analyses, individuals with requisite experience in risk assessment are frequently relied upon to select the appropriate analysis levels for the hazard, vulnerability, and system performance based on their experience and the documentation that is available to them for study.

As an alternative to the reliance solely on such experience and intuition, systematic scoring procedures for determining levels of detailed analyses have been developed in industry guidelines. The ALA guidelines suggest levels of analysis for hazard and vulnerability analyses.

Tables 8-4 and 8-5 have been extracted from the ALA guidelines. These tables illustrate the three potential levels of analysis and typical technical process to be followed for each level. Table 8-4 illustrates the three levels of hazard analysis (HE, H2, H3), and Table 8-5 illustrates vulnerability analysis levels (V1-V2, and V3) that might be appropriate, depending on the issue and the results desired.

The levels of analysis selected are dependent on the objectives of the study, the budget and schedule, and the type and quality of technical data available. For example, the most detailed Hazard Analysis at Level 3 requires the most resources—financial, schedule, and technical; the least detailed, Level 1, requires the lowest. Some of the required steps of both the highest Level 3 and intermediate Level 2 analyses require field reconnaissance for earthquake, frost, flood, and other hazards (by qualified natural specialists such as geologists, seismologists, etc.), and the investigation of local geotechnical conditions such as the conduct of soil borings and cone penetration tests. The analytic methods recommended include performance of flood hazards analysis using computer codes such as HEC RAS, HAZUS-MH, and system-wide probabilistic wind hazard assessments. Access to the individual nodes and much of the data required for Levels 2 and 3 will likely not be available to the project. This project is not scoped to include local site engineering of hazards or design level engineering analytic studies of individual nodes.

The proposed methodology for detailed natural hazards nodes study is to implement a Level 1 type assessment of nodes that pass the initial natural hazards screening. The project would 1) rely on topographic and regional level hazard maps, 2) review existing engineering data, soil borings, test pits, and ditch logs (if available), 3) rely on expert judgment for hazards such as soils stability and settlement, frost heave, tsunami hazards, and 4) estimate ground motion levels, liquefaction, and faulting using engineering judgment and existing regional maps.

Based on the initial review of available hazards information and the possibility that owner/operator data and access to nodes will not be available, even the performance of a Level 1 analysis, as recommended in the ALA guidelines,[2] may leave unsatisfied some data requirements associated with local natural hazard impacts.

Table 8-4 Detailed Assessment of Hazards (H1-3) - Excerpts of Evaluation Matrices

Hazard/Task		Notes	H1	H2	H3
2.2.7	Evaluate settlement potential using advanced analytical methods	2			◆
2.2.8	Determine potential for manmade-induced settlement (e.g., groundwater withdrawal)		◆	◆	◆
2.3 Ground Deformation Hazard – Frost Heave					
2.3.1	Review surface geology maps		◆	◆	◆
2.3.2	Perform field reconnaissance (by qualified geotechnical engineers)			◆	◆
2.3.3	Review existing soil borings, test pits, and ditch logs, as available		◆	◆	◆
2.3.4	Conduct limited soil borings			◆	◆
2.3.5	Conduct extensive soil borings				◆
2.3.6	Evaluate frost-heave potential using expert judgment	2	◆	◆	◆
2.3.7	Evaluate frost-heave potential using empirical methods	2		◆	◆
2.3.8	Evaluate frost-heave potential using advanced analytical methods	2			◆
3 Wind Hazard					
3.1	Review national wind maps (ASCE 7-02)		◆	◆	◆
3.2	Review literature on local wind history		◆	◆	◆
3.3	Identify local conditions that may increase wind hazard	5		◆	◆
3.4	Gather historical storm (hurricane) patterns	6		◆	◆
3.5	Identify potential windstorms using expert judgment		◆	◆	◆
3.6	Conduct field evaluations			◆	◆
3.7	Estimate potential wind hazards using expert judgment		◆	◆	◆
3.8	Perform systemwide probabilistic wind hazard assessment (PWHA)	2			◆
4 Icing Hazard					
4.1	Review national icing hazard map (ASCE 7-02)		◆	◆	◆
4.2	Review literature on local icing history		◆	◆	◆
4.3	Identify local conditions that may increase icing hazard			◆	◆
4.4	Estimate potential icing hazards using expert judgment		◆	◆	◆
4.5	Perform systemwide probabilistic icing hazard assessment				◆
5 Flooding Hazard					
5.1	Review Q3 digital flood maps and national Flood Insurance Rate Maps	7	◆	◆	◆
5.3	Gather local flood data from local/regional jurisdiction	8	◆	◆	◆
5.4	Overlay flood maps onto system maps			◆	◆
5.5	Collect topographic, stream, rainfall data			◆	◆
5.6	Identify potential flooding hazard from local dams or floodways		◆	◆	◆
5.7	Evaluate flooding potential using expert judgment		◆	◆	◆
5.8	Perform analytical flood hazard analysis (HEC RAS, HAZUS-MH)	2		◆	◆

Note: From ALA Oil & Gas Guideline for Oil and Natural Gas Pipeline Systems in Natural Hazard Events.

Table 8-5 Detailed Assessment of Node Vulnerability Levels (V1-3) - Excerpts of Evaluation Matrices

Component/Task	Notes	V1	V2	V3
1 Assess Pipeline Vulnerability to Ground Movement Hazards				
1.1 Assess crossings of potential ground movement hazards entirely by engineering judgment for various levels of permanent ground deformation.		◆	◆	◆
1.2 Detailed pipeline analysis for a limited number of representative cases according to pipe diameter, wall thickness, direction of movement relative to pipeline, etc.			◆	◆
1.3 Detailed pipeline analysis for site-specific cases			◆	◆
1.4 Determine pipeline strain criteria based on knowledge of current condition of pipe and welds and review of technical literature on pipe performance	1	◆	◆	◆
1.5 Determine pipeline strain criteria using pipe shell FEA models.	1		◆	◆
1.6 Determine pipeline analysis acceptance criteria using laboratory test programs coupled with pipe shell finite element analysis	1			◆
2 Fragility Assessment of Critical Buildings				
2.1 Gather information by interviewing company operations managers and building maintenance personnel		◆	◆	◆
2.2 Identify critical functions within buildings and the damage that would impair or impede these functions		◆	◆	◆
2.3 Perform general site survey(s) to assess local conditions and to collect information on the general vulnerability of buildings, their contents, and any nearby equipment and their supports	2		◆	◆
2.4 Perform general site survey(s) to assess collateral hazards from off-site sources and nearby structures and equipment	3		◆	◆
2.5 Assess performance of building and support equipment using judgment (estimates or informed estimates) and/or experience (statistical) data from past events or using empirical damage models with minimal field data collection	4	◆	◆	◆
2.6 Review architectural and structural drawings, design calculations, foundation investigation reports, and past structural assessment reports to assess building capacity			◆	◆
2.7 Perform independent structural calculations to assess building capacity	4		◆	◆
2.8 Develop computer-based structural analysis model(s) to assess building response	4			◆
3 Assess Storage Tanks				
3.1 Assess tank structural integrity by engineering judgment		◆	◆	◆
3.2 Assess tank structural integrity using API 650 Standard or equivalent tank design methodology			◆	◆
3.3 Assess effects of tank overtopping by sloshing			◆	◆
3.4 Assess effects of tank sloshing on floating roofs (internal or external)			◆	◆

Note: From ALA Oil & Gas Guideline for Oil and Natural Gas Pipeline Systems in Natural Hazard Events.

9 RISK ASSESSMENT RESULTS

Operational and natural hazard assessments will be summarized and presented to the State during the final phase of this project. The summary will include a discussion of 1) components of the final risk assessment database(s), 2) the three ways data will be summarized for presentation to the State and how these formats might be used by the State in future risk management efforts, and 3) how risks in each of the three consequence categories can be compared.

9.1 Risk Data

The primary outcome of this project will be a risk profile of the Alaska oil and gas infrastructure that can be used by the State to manage the risk of unplanned oil and gas production outages from significant hazardous events. Such risk management decisions include answering questions such as:

- What risk management initiatives should be pursued?
- What risk management initiatives should not be pursued?
- How much money should reasonably be spent on risk management?
- How should that money be spent to obtain the most value?

The operational hazards (Section 7) and natural hazards (Section 8) methodologies both address the development of potentially hazardous scenarios/events, the assessment of frequencies, and the calculation of consequences (in terms of safety, environmental, and reliability impacts) associated with each event. The risk data that results from these assessments will be compiled into a database of the individual scenarios considered as part of the overall risk assessment. For each scenario, the database will provide information including:

- Node identifier, which includes the following information that will be accessible in a node data file:
  - Node name
  - Infrastructure region (e.g., North Slope, TAPS, Cook Inlet)
  - Facility (if any) that contains the node
  - Facility type
  - Node location
  - Owner/operator
  - Production throughput associated with the node
- Scenario description
- Scenario frequency
- Safety consequence estimate *(fatalities per event)*
- Safety consequence category
- Environmental consequence estimate *(environmental index value)*
- Environmental consequence category
- Reliability consequence estimate *(dollars per event)*
- Reliability consequence category

9.2 Risk Summary Formats

After the risk assessment database is populated, the risk assessment results will be summarized and presented in three different formats that will help the State and other users to visualize the results of the project. The basis for these formats will be "major risk contributors" and "contributing factors". Major risk contributors are the individual nodes or groups of nodes that present the most risk. Contributing factors reflect the characteristics of the scenarios or nodes (e.g., locations, component types, failure type) that are common to several relatively important risk contributors. Presentation formats will include:

- **Risk Matrices-** shows the number of events by risk level (based on frequency and consequence)
- **Risk Histograms-** shows total estimated frequency for events assigned to each of the consequence categories
- **Risk Summaries-** shows percentages of safety and reliability risk based on characteristics of the scenario and node. Risk summaries will be provided for the following:
  - Facility
  - Facility type
  - Operating area (i.e. North Slope, Cook Inlet, TAPS)
  - Owners/Operators
  - Natural hazard (when applicable)

The first two risk presentation formats will be provided for all three classes of consequence (i.e., safety, environmental, and reliability). The third format will be provided for safety and reliability risk only. (See Section 9.2.3 for a detailed discussion of the reasons it is not appropriate to provide risk summaries for environmental risk as analyzed in this project.)

9.2.1 Risk Matrices

Risk matrices display the number of scenarios that have been assigned to each combination of frequency category and specific consequence category.[37,38] Figure 9-1 provides an example of a risk matrix for reliability consequences (e.g., loss of revenue to the State due to production losses). The vertical axis shows example frequency categories and the horizontal axis presents reliability consequence categories using the reliability consequence categories provided in Table 6-3.

FREQUENCY CATEGORY	Cat 1	Cat 2	Cat 3	Category Frequency Range	Years Between Events
	<4,200,000 bbls	4,200,000 to 42,000,000 bbls	>42,000,000 bbls		
5				> 1 every 10 years	<10
4	12			.1 to .033 events per year	10 to 30
3	27	5		.033 to .01 events/yr	30 to 100
2	45	8	4	.01 to .0033 events/yr	100 to 300
1	76	10	6	<.0033 events/yr	>300

Figure 9-1 Example Risk Results in a Risk Matrix Format

Figure 9-1, which reflects hypothetical reliability consequence results, identified a total of 193 scenarios that had significant reliability consequences—160 scenarios in Category 1, 23 scenarios in Category 2, and 10 scenarios in Category 3 (these numbers represent the sum of the number of scenarios in each column of the risk matrix). Of the 10 scenarios estimated as having Consequence Category 3 reliability impacts, four of them occur once in 100 to 300 years (i.e., Frequency Category 2). The other six scenarios in Consequence Category 3 are less likely, with individual scenarios occurring less than once in 300 years.

Risk data in this format is often used to identify events of concern. For example, one approach might be to focus only on the most severe events (i.e., the Consequence Category 3 events). Another approach might be to examine the events in each consequence category that occur most frequently (i.e., the 12 events in Consequence Category 1, the 5 events in Consequence Category 2, and the 4 events in Consequence Category 1).

When using risk data in this format, the decision to focus risk reduction efforts on specific events will depend on the State's attitude toward risk management and willingness to accept certain risk levels. For example, in many cases risk managers choose to investigate the risks represented in the portion of the matrix that reflects the highest frequency/consequence combination, (i.e., some number of cells in the upper right in the matrix) by collecting and documenting information about:

- What the organization currently does to control those risks, and
- Other risk mitigation measures might be considered

Risk matrix tools are applicable for use in examining the three consequences of interest pertinent to this project (i.e., estimates of safety, environmental, and reliability/revenue risk). It was noted that in the review of the methodology proposed by the Transportation Research Board for the *Risk of Vessel Accidents and Spills in the Aleutian Islands* that the risk matrix approach was specified for use in the evaluation of potential risks. [39]

9.2.2 Risk Histograms

Another way to examine risk results when events are assigned to consequence categories is to sum the frequency of all of the events that could contribute to each consequence category. (This presentation is typically called a risk histogram.)[40] Figure 9-2 presents hypothetical reliability risk estimates for the scenarios in each of the three reliability consequence categories.

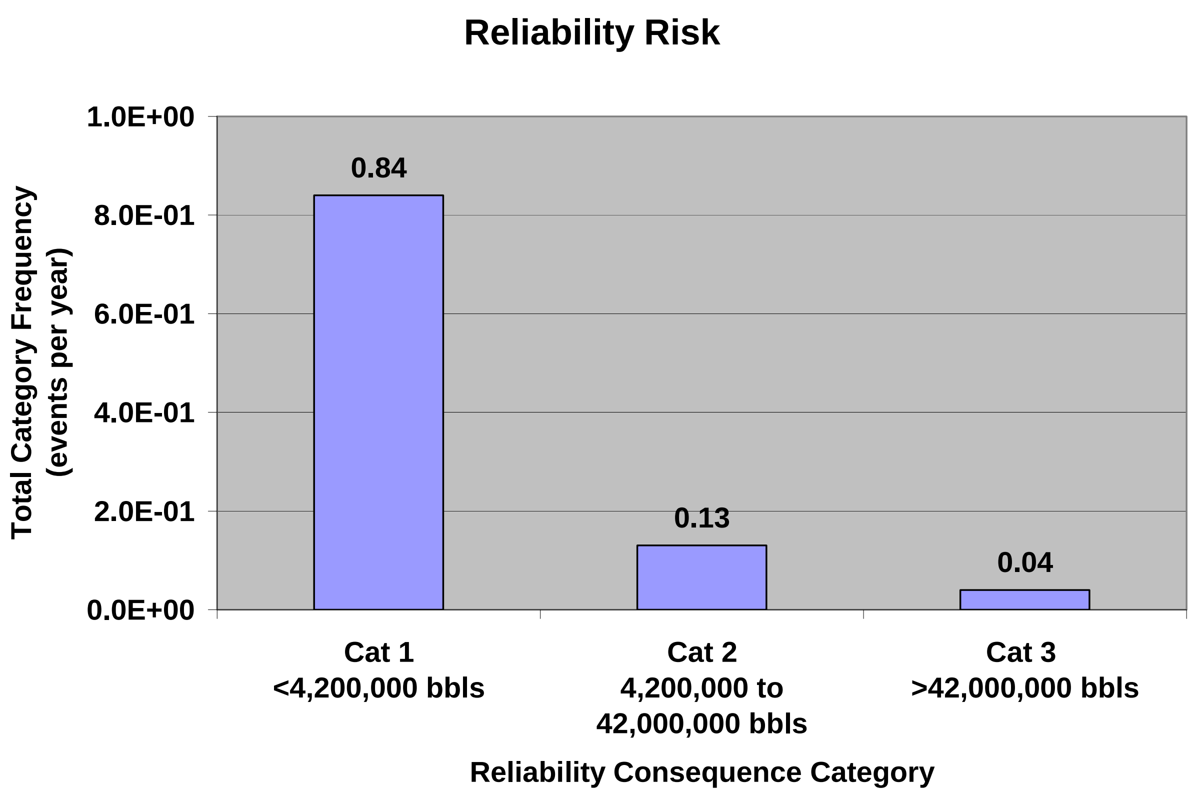

Figure 9-2 Reliability Risk Histogram

Figure 9-2 shows that the overall frequency of events that fall into Reliability Consequence Category 1 is 0.84 events per year (slightly less than one event per year). That frequency is 6 times higher than the estimated frequency for Consequence Category 2 events (i.e., 0.13 events per year) and more than 20 times higher than the frequency for Consequence Category 3 events (0.025 events per year). This type of presentation for risk data will help to verify the credibility of the study results by validating that the level of actual experience is consistent with the risk assessment results. If experience and the risk assessment results are not consistent, the Project Team will need to understand why these differences exist. For example, if conditions have changed, the histogram may show a different level of risk in the future than has existed in the past. The purpose of the histogram is to create a baseline of the state of the infrastructure which will aid in predicting future risks.

For consequence categories that are less likely, the frequency estimate provides data for consideration by risk management planners. For example, Figure 9-2 shows that events in Consequence Category 3 are estimated to occur approximately once in 25 years (i.e., a frequency of .04 per year). Based on this type of information, the State and the infrastructure operators may make risk management and financial decisions regarding how much money they are willing to spend to prevent a risk of a specific magnitude (i.e., Consequence Category 3) at that frequency.

Risk histograms that examine frequency results by consequence category are applicable for examining all three types of consequences of interest in this project (i.e., safety, environmental, and reliability).

9.2.3 Risk Estimates

The risk matrix and risk histogram approaches discussed in the previous sections both depend on the consideration of frequency and consequence as separate numbers or categories. This section describes another approach to examine the risk of a scenario, which involves calculating a specific risk using the classical risk equation. For the example of reliability risk, this equation is:

Risk (barrels per year) =Frequency (events per year) X Consequence (barrels per event)

Equation 9-1 Reliability Risk Equation

This risk data will be available on a scenario basis, and a minimum of one risk estimate will be calculated for every scenario. For example, if based on preliminary risk screening, a node is at potentially high risk for reliability issues; one or more reliability risk scenarios applicable to that node will be developed. Each scenario will have a specific frequency and consequence associated with it and a risk estimate will be developed using the equation above. Once risks have been estimated for each scenario, risk totals can be summed for a collection of scenarios to calculate risks for a group of:

- Nodes
- Facilities
- Facility types
- Operating areas
- Owners/Operators
- Natural hazards (when applicable)

As the detailed analysis is performed, the scenario attributes listed above will be documented so “risk roll-ups” can be performed. That data can then be used to create graphs like Figure 9-3 which depicts three hypothetical operating areas of the infrastructure.

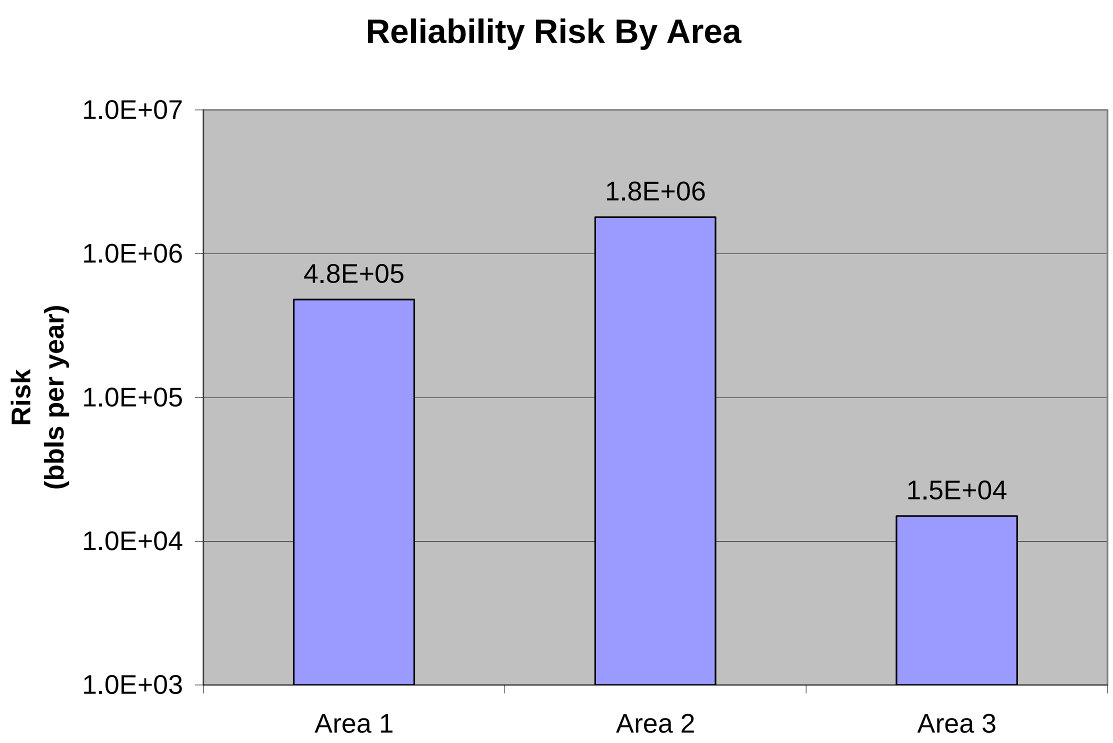

Figure 9-3 Reliability Risk by Area

Risk values for scenarios and risks summed for nodes or other attributes of the scenarios can aid the State in answering questions such as:

- Which nodes are the largest contributors to the estimated reliability risks?
- What fraction of the estimated reliability risk is associated with nodes that are part of TAPS?
- What fractions of the estimated reliability risk are associated with each infrastructure owner/operator?

This risk summarization approach is effective in cases where the consequence is estimated in a continuous manner, such as the safety and reliability consequences proposed in this project (see Section 6) for which "number of potential fatalities" and "barrels of production lost," are the units of measure that are used to represent the impacts, respectively. However, because the project approach for evaluating environmental impact uses an environmental index for which there is no directly applicable unit of measure, it is not appropriate to estimate the scenario risk using this technique. That means it will not be possible to sum the resulting "environmental risks" from different scenarios and estimate environmental risks for groups of scenarios. For the environmental consequence risk assessment, only the risk matrix and risk histogram approaches described previously will be used for the presentation of results.

9.3 Risk Comparisons

A number of risk comparisons can be made using results from this project. Risk for a particular node of the oil and gas infrastructure is estimated by analyzing the risk of various scenarios involving that node. A specific node may have multiple scenarios that present significant risks. Similarly, a single scenario may result in significant risks in one, two or all three of the classes of consequence of interest specific to this project (i.e., safety, environmental, or reliability risk). For example, the highest reliability risk for a given node may result from one scenario (e.g., long term outage of a support system required for operation) while the highest safety risk for that same node might result from another kind of scenario entirely (e.g., a gas release and explosion in a congested or confined area that can affect local accommodation facilities).

Within a single consequence class, different scenarios can be compared by frequency, or consequence, or their estimated risk (except as explained previously for environmental risk.

It is much more difficult to compare risks across consequence classes, such as comparing safety or environmental risks to reliability risks, because they are represented in different risk units (e.g., dollars per year for reliability risk and fatalities per year for safety risk). In some risk applications (e.g., development of safety or environmental regulations), agencies have assigned an explicit value to a life lost due to an accident. This allows for the conversion of a risk result that is in units of fatalities per year to dollars per year (by multiplying by dollars per fatality). It is not suggested that the State convert safety risks to units of dollars per year for this risk assessment, in part because the issue of loss of human life is a highly sensitive one, but also because the financial loss that associated with a production interruption for this project is specific to the impact to state revenue.

For environmental risks, some studies use the cost of remediation as the means for assigning a value to the consequence of an unplanned event with environmental impacts. That approach allows direct comparison of environmental risks with other risk categories, which can be expressed in terms of dollars per year. However, this approach has not been selected for use in this project because it cannot appropriately respond to the input received from a large number of stakeholders during the consultation portion of this project. Stakeholders clearly voiced concerns relating to events that could impact unique Alaskan habitats and resources, traditional way of life, including subsistence, and Alaska's reputation. These stakeholders placed a high value on identifying types of accidents that could have a significant impact on the external environment and preventing them from occurring. A focus solely on response and remediation of environmental incidents after they have already occurred cannot fully address these concerns.

Consequently, an environmental index that represents multiple consequence aspects rather than cost of remediation was selected for use. The environmental index is a relative ranking tool that considers spill composition, spill quantity, environmental sensitivity of the area, and ability to remediate the spill. Use of such a relative ranking index is a common practice in risk based decision-making efforts.[41] However, it does not allow direct comparisons of risks between environmental risks and other risk categories being examined in this project.

10 ENDNOTES

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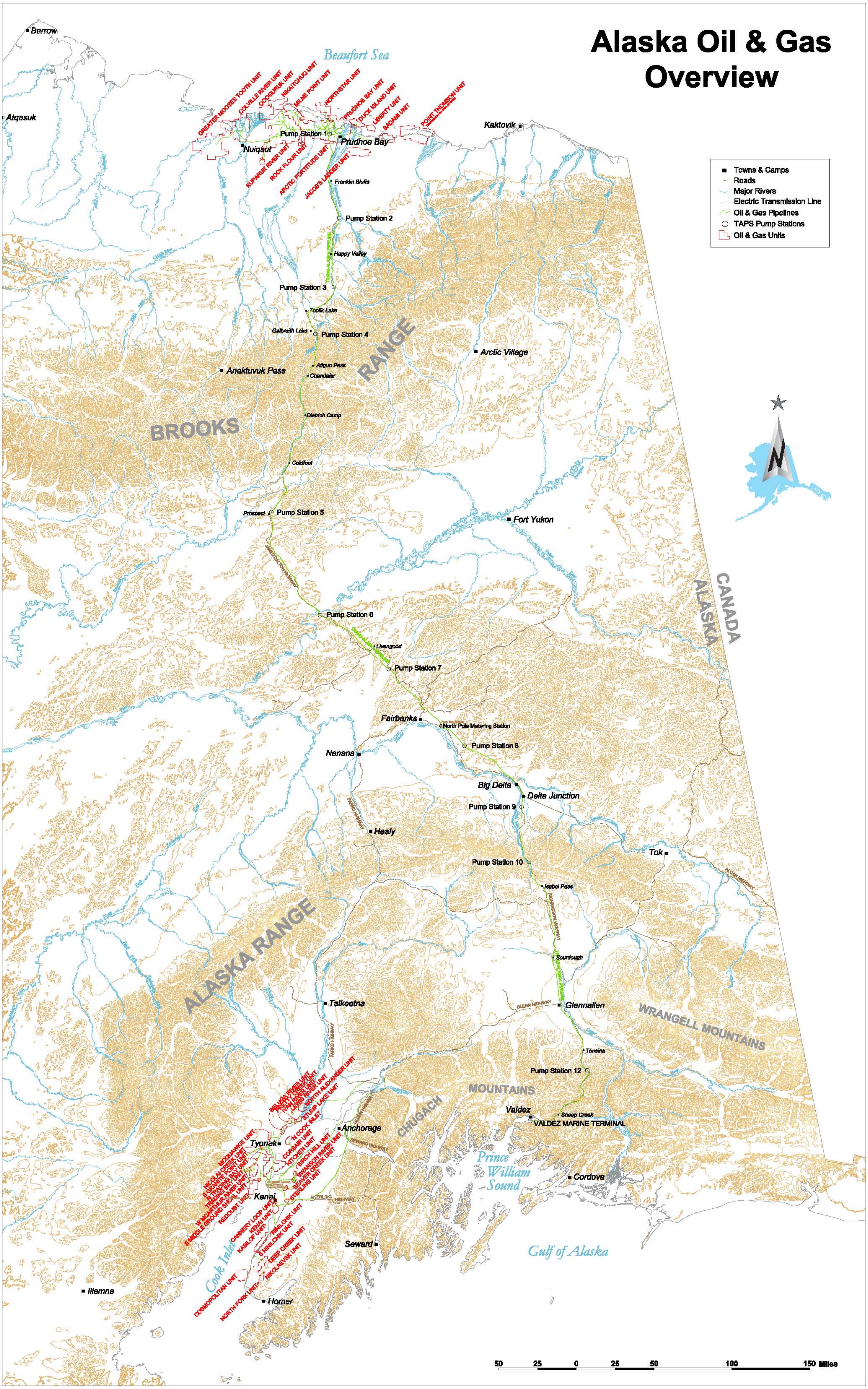
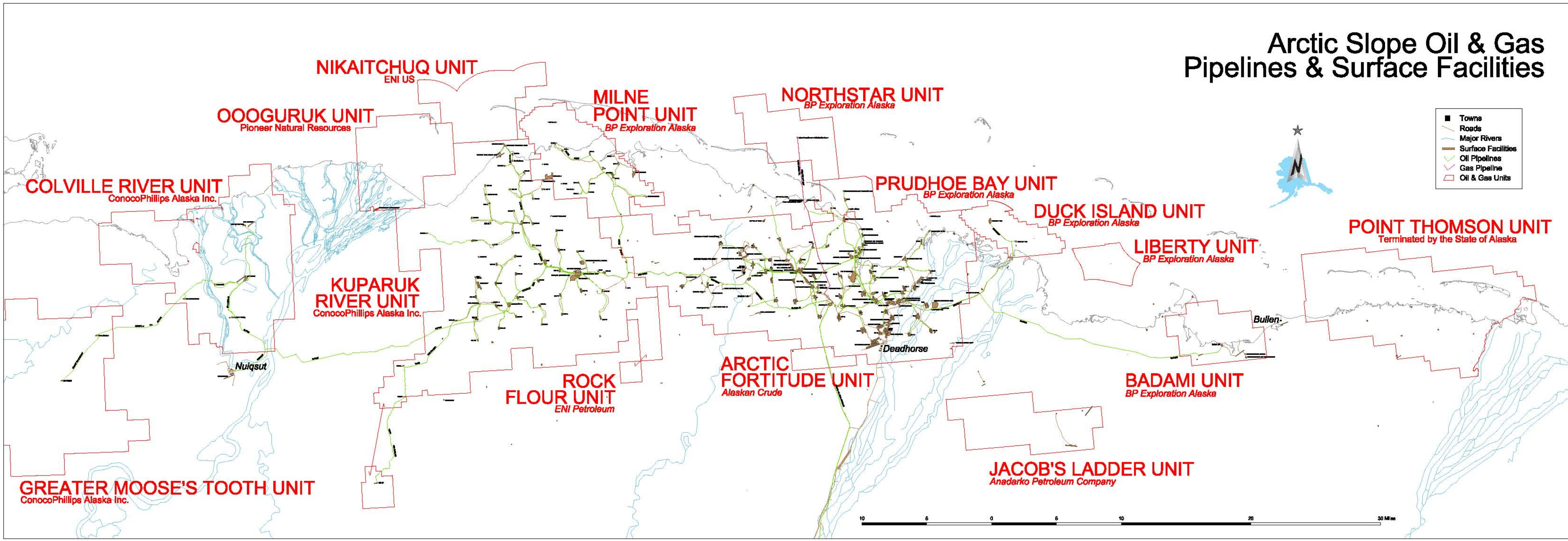
Appendix A. Alaska Infrastructure Maps

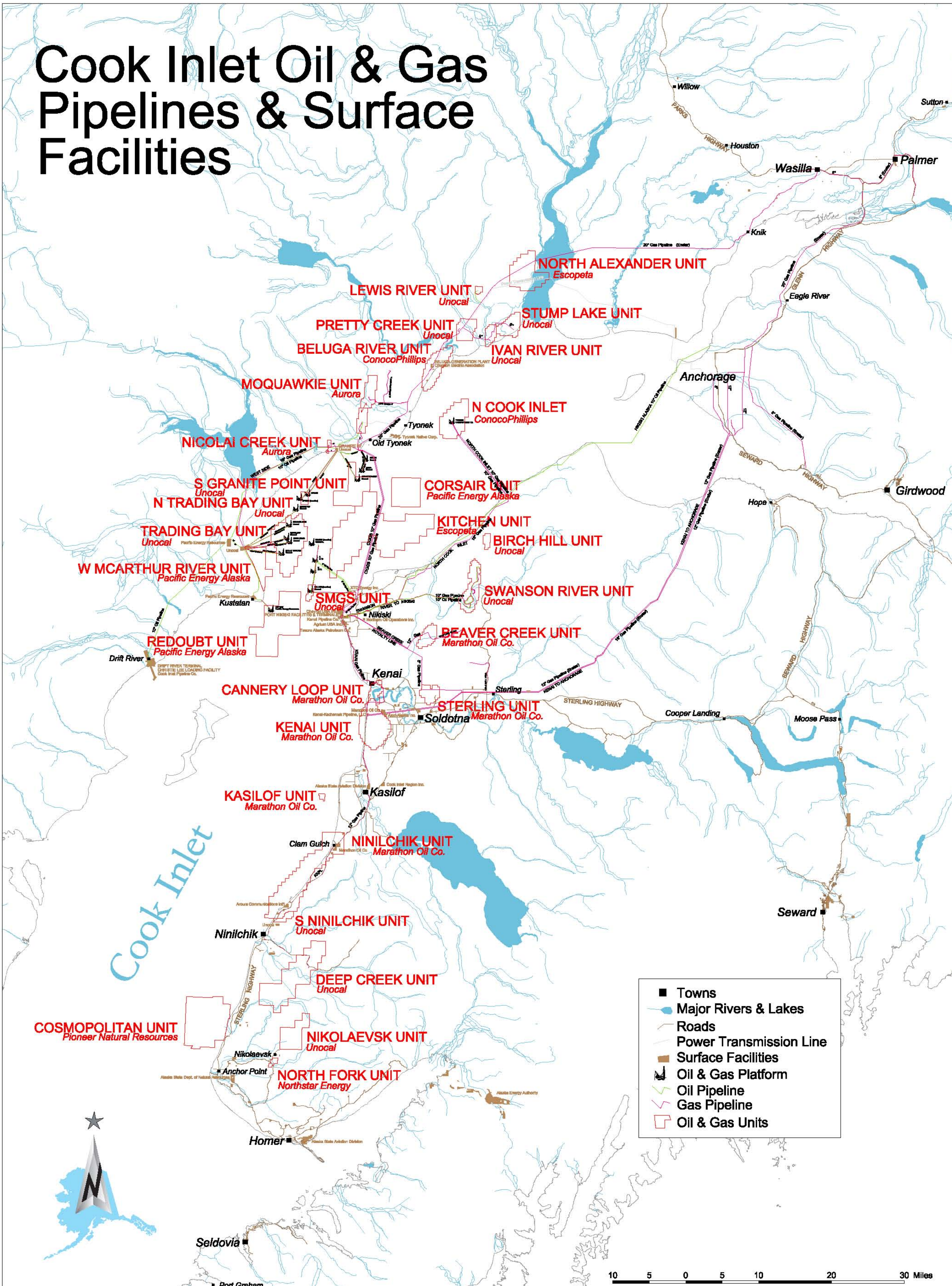


Alaska Oil & Gas Overview
Towns & Camps
Roads
Major Rivers
Electric Transmission Line
Oil & Gas Pipelines
TAPS Pump Stations
Oil & Gas Units
Beaufort Sea
Barrow
Atqasuk
Nuiqsut
Kaktovik
Pump Station 1
Prudhoe Bay
Franklin Bluffs
Pump Station 2
Happy Valley
Pump Station 3
Toolik Lake
Galbreith Lake
Pump Station 4
Atigun Pass
Chandalar
Arctic Village
Anaktuvuk Pass
BROOKS RANGE
Dietrich Camp
Coldfoot
Prospect
Pump Station 5
Fort Yukon
CANADA
ALASKA
Pump Station 6
Livengood
Pump Station 7
Fairbanks
North Pole Metering Station
Pump Station 8
Nenana
Big Delta
Delta Junction
Pump Station 9
Healy
Tok
Pump Station 10
Isabel Pass
ALASKA RANGE
Sourdough
Talkeetna
Glennallen
WRANGELL MOUNTAINS
Tonsina
Pump Station 12
CHUGACH MOUNTAINS
Valdez
Sheep Creek
VALDEZ MARINE TERMINAL
Anchorage
Tyonek
Prince William Sound
Cordova
Kenai
Seward
Gulf of Alaska
Cook Inlet
Iliamna
Homer
GREATER MOOSES TOOTH UNIT
COLVILLE RIVER UNIT
OOOGURUK UNIT
NIKAITCHUQ UNIT
MILNE POINT UNIT
NORTHSTAR UNIT
PRUDHOE BAY UNIT
DUCK ISLAND UNIT
LIBERTY UNIT
BADAMI UNIT
POINT THOMSON UNIT
KUPARUK RIVER UNIT
ROCK FLOUR UNIT
ARCTIC FORTITUDE UNIT
JACOB'S LADDER UNIT
NORTH ALEXANDER UNIT
STUMP LAKE UNIT
N COOK INLET
CORSAIR UNIT
KITCHEN UNIT
BIRCH HILL UNIT
SWANSON RIVER UNIT
BEAVER CREEK UNIT
STERLING UNIT
MOQUAWKIE UNIT
REDOUBT UNIT
CANNERY LOOP UNIT
KENAI UNIT
KASILOF UNIT
NINILCHIK UNIT
DEEP CREEK UNIT
NIKOLAEVSK UNIT
COSMOPOLITAN UNIT
NORTH FORK UNIT
S MIDDLE GROUND SHOAL UNIT
W MCARTHUR RIVER UNIT
TRADING BAY UNIT
GLENN HIGHWAY
STERLING HIGHWAY
SEWARD HIGHWAY
PARKS HIGHWAY
ALCAN HIGHWAY
RICHARDSON HIGHWAY
JAMES DALTON HIGHWAY
50 25 0 25 50 100 150 Miles



Arctic Slope Oil & Gas
Pipelines & Surface Facilities
Towns
Roads
Major Rivers
Surface Facilities
Oil Pipelines
Gas Pipeline
Oil & Gas Units
NIKAITCHUQ UNIT
ENI US
OOOGURUK UNIT
Pioneer Natural Resources
MILNE
POINT UNIT
BP Exploration Alaska
NORTHSTAR UNIT
BP Exploration Alaska
COLVILLE RIVER UNIT
ConocoPhillips Alaska Inc.
PRUDHOE BAY UNIT
BP Exploration Alaska
DUCK ISLAND UNIT
BP Exploration Alaska
LIBERTY UNIT
BP Exploration Alaska
POINT THOMSON UNIT
Terminated by the State of Alaska
KUPARUK
RIVER UNIT
ConocoPhillips Alaska Inc.
Bullen
Deadhorse
Nuiqsut
ARCTIC
FORTITUDE UNIT
Alaskan Crude
ROCK
FLOUR UNIT
ENI Petroleum
BADAMI UNIT
BP Exploration Alaska
JACOB'S LADDER UNIT
Anadarko Petroleum Company
GREATER MOOSE'S TOOTH UNIT
ConocoPhillips Alaska Inc.
10
5
0
5
10
20
30 Miles

Cook Inlet Oil & Gas Pipelines & Surface Facilities



Appendix B. Environmental Discharge Thresholds Summary

Spill Scenario	Sub Area				Scenario Description	Fluid Type	Spill Volume	
	North Slope[1]	Interior Alaska[2]	Cook Inlet[3]	PWS[4]			Barrels	Gallons
Subarea Contingency Plan Scenarios								
Worst Case (Coastal)	X				Well Blowout spill to ocean of 5,000 BBLs/day for 60 days	Oil	300,000	13,000,000
			X		Tanker spill to ocean	Oil	380,000	16,000,000
				X	Tanker spill to ocean	Oil	2,200,000	92,400,000
Worst Case (Inland)	X				Kuparuk pipeline spill to Kuparuk River	Oil	10,516	441,672
		X			TAPS spill migrating to River	Oil	49,450	2,077,000
			X		Pipeline spill to wetlands	Oil	2,400	100,000
				X	TAPS spill migrating to River	Oil	40,000	1,680,000
Maximum Most Probable (Coastal)	X				Barge spill to ocean	Diesel	500	21,000
			X		Well Blowout spill to ocean of 5,000 BBLs/day for 60 days	Oil	300,000	13,000,000
				X	Tanker (Exxon Valdez) spill to ocean	Oil	257,000	10,800,000
Maximum Most Probable (Inland)	X				Oil Transit Pipeline spill to tundra between Gathering Centers	Oil	4,800	200,000
		X			Rail tanker spill migrating to River	Jet Fuel	595	25,000
			X		Transportation spill to wetlands	Fuel Oil	48	2,000
				X	TAPS check valve (reference CV-92) spill underground	Oil	710	30,000
Average Most Probable (Coastal)	X				Vessel transfer spill to ocean	Diesel	1.2	50
			X		Vessel transfer spill to ocean	Diesel	50	2,100
				X	Vessel transfer spill to ocean	Diesel	25	1,050
Average Most Probable (Inland)	X				Haul road truck spill to tundra	Oil/Diesel	6.31	265
		X			Tanker truck spill migrating to River	Gasoline	24	1,000
			X		Refinery tank overfill spill to uplands	Oil	0.31	13
				X	Tanker truck spill migrating to River	Diesel	190	8,000

Regulation/Requirement	Description		Spill Volume	
			Barrels	Gallons
Supplemental Reference Information				
Oil and Hazardous Substances Pollution Control Reporting Thresholds[5]	Immediate Reporting: Oil spill to water or oil spill to land outside of containment		> 1.3	> 55
	48 Hour Reporting	Oil spill to land outside of containment	0.24 – 1.3	10-55
		Oil spill to containment	> 1.3	> 55
	Monthly Reporting: Oil spill to land		< 0.24	< 10
	"Major Discharge" Definition	Spill to Inland Waters	240	10,000
		Spill to Coastal Waters	2,400	100,000
	"Regulated Above Ground Oil Storage Tank" Definition		240	10,000
Facility Response Plan Rule for "Substantial Harm" is a facility that:[6]	1. Has a total oil storage capacity greater than or equal to 42,000 gallons and it transfers oil over water to/from vessels; or		> 1,000	> 42,000
	2. Has a total oil storage capacity greater than or equal to one million gallons and meets one of the following conditions:	Does not have sufficient secondary containment for each aboveground storage area	> 24,000	> 1,000,000
		Is located at a distance such that a discharge from the facility could cause "injury" to fish, wildlife, and sensitive environments		
		Is located at a distance such that a discharge from the facility would shut down a public drinking water intake		
		Has had, within the past five years, a reportable discharge greater than or equal to 10,000 gallons	> 240	> 10,000
SPCC Above Ground Storage Threshold for Plan[6]			31	1,320
SPCC Regional Administrator Reporting Requirement:[6]	Single oil spill to water		24	1,000
	2 oil spill events during 12 month period		> 1	> 42

Regulation/Requirement	Description	Spill Volume	
		Barrels	Gallons
Federal spill reporting requirements are as follows: Discharges of oil in such quantities that the Administrator of the EPA has determined may be harmful to the public health or welfare or the environment of the United States include discharges of oil that: (a) Violate applicable water quality standards; or (b) Cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or a cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines. Waters of the U.S. include ocean, rivers, streams, creeks, lakes, mudflats, sandflats, wetlands such as tundra on the North Slope, and dry channels in hydraulic connection to such waters.[7] There is no distinction between oil and produced water since either can cause a sheen.			
Typical Industry Environmental Risk Assessment Spill Guidelines	High Range: with widespread impact	1,000	42,000
	Medium Range: limited impact	10 – 1,000	420 – 42,000
	Low Range: contained with no impact	10	420

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Appendix C. Operational Hazards Data Requirements

Table C-1 Facility-specific Data Required for Operational Hazards

Facility-specific Data Required for Operational Hazards
Facility layouts and Process Flow Diagrams (PFDs)
Process and Instrumentation Diagrams (P&IDs)
List of major equipment and age of equipment
Equipment maintenance records, including work orders
Process and storage inventories
Rotating equipment reliability data – failure history
Physical, chemical, and hazardous properties of process materials
List of isolation and emergency shutdown devices
Process leak detection system data (i.e., gas, fire, heat, ultraviolet detection systems)
Fire suppression system information
Utility system information
Vents and relief systems information
Emergency response plans and evacuation plans
Past incidents history
Meteorological data for facility location
Number of workers on shift during days and nights
Maintenance and equipment inspection history data
Major equipment repair and restoration times

Table C-2 Pipeline-specific Data Required for Operational Hazards

Pipeline-specific Data Required for Operational Hazards
Compositions, Physical and Chemical Properties of Materials transported
Pipeline Length and Topography
Age (year constructed)
Material of Construction
Pipeline Wall Thickness
Locations & Depth of Burial
Construction Method (Welding)
Corrosion Protection Method
Pipeline Outer Diameter
Operating Pressure
Design Pressure
Shutoff Valves (type/location)
Inspection History (type, frequency, findings)
Repair/Test History (including hydrotest and operating pressure after repair)
Leak detection system data

Table C-3 Publicly Available Required Facility-specific Data for Operational Hazards

Publicly Available Facility-specific Data for Operational Hazards
Meteorological data for facility location
Wind roses (for 8 directions) and stability class data for North Slope, TAPS Corridor, and Cook Inlet
Topographical data for the North Slope region, Cook Inlet region, and along TAPS Corridor
Population data – North Slope, near TAPS Corridor, and Cook Inlet Facilities
Population density (numbers per square yards or another unit of area)
Location of nearby lakes and rivers in close proximity to (or crossed by) facilities and pipelines
Environmentally sensitive areas adjacent to facilities
Cook Inlet metocean data (winds, waves, and current)
Extreme temperatures and precipitations

Table C-4 Industry-wide Reliability Data Sources for Operational Hazards

Industry-wide Reliability Data Sources for Operational Hazards	
Data Source	**Equipment Covered**
US DOT Pipeline and Hazardous Materials Safety Administration	Transmission and gathering pipeline failure statistics
European Gas Pipeline Incident Data Group (EGIG)	Gas pipeline statistics
Conservation of Clean Air and Water in Europe (CONCAWE) - Performance of European cross-country oil pipelines Statistical summary of reported spillages in 2006 and since 1971	Oil pipeline cross country failure statistics
Parloc 201 - The Update of Loss of Containment for Offshore Pipelines	Offshore pipeline failure statistics
MIL-HDBK-217F - Reliability Prediction of Electronic Equipment	Electronic components
United Kingdom Onshore Pipeline Operators' Association (UKOPA) Database for UK Gas Pipeline Data	Gas transmission pipeline failure statistics
Electronic Parts Reliability Data (EPRD) - RIAC Data	Electronic components
NPRD-95 Non-electronic Parts Reliability Data - RIAC Data	Mechanical and electro-mechanical components
FMD-97 Failure Mode/Mechanism Distributions - RIAC Data	Electronic, electrical, mechanical and electro-mechanical components
System and Part Integrated Data Report (SPIDR) - System Reliability Center	Electronic and electro-mechanical components
SR-332 Reliability Prediction for Electronic Equipment - Telcordia Technologies	Electronic components
European Industry Reliability Data (EiReDA)	Mainly components in nuclear power plants
Offshore Reliability Data (OREDA)	Topside and subsea equipment for offshore oil and gas production

Industry-wide Reliability Data Sources for Operational Hazards	
Data Source	**Equipment Covered**
Table C-4, cont.	
MechRel - Handbook of Reliability Prediction for Mechanical Equipment	Mechanical equipment - military applications
Reliability Data of Components in Nordic Nuclear Power Plants – T-Book	Components in nuclear power plants
Reliability Data for Control and Safety Systems - PDS Data Handbook	Sensors, detectors, valves & control logic
Safety Equipment Reliability Handbook - Exida	Safety equipment (sensors, logic units, actuators)
WellMaster - ExproSoft	Components in oil wells
SubseaMaster - ExproSoft	Components in subsea oil/gas production systems
Process Equipment Reliability Data (PERD) - AIChE	Process equipment
Government-Industry Data Exchange Program (GIDEP)	
Center for Chemical Process Safety (CCPS) Guidelines for Process Equipment Reliability Data - AIChE, 1989	Process equipment
Failure Rate Data In Perspective (FARADIP) Data	Electronic, electrical, mechanical, pneumatic equipment
IEEE Std. 500-1984: Institute of Electrical and Electronics Engineers, Inc. (IEEE) Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component, and Mechanical Equipment Reliability Data for Nuclear Power Generating Stations	See title for equipment covered

Appendix D. Hydrocarbon Release Models

D-1 Rate of Release

The consequence analysis begins by postulating the initiating event aperture sizes (holes), which are often expressed in three classes: small, medium, and large. The equivalent diameters of the apertures will be defined and maintained consistently throughout the project.

Incident Hole Size

The following equivalent hole sizes in the release models will be used:

1. Small: 1 in. (~25 mm) equivalent diameter
2. Medium: 2 in. (~50 mm) equivalent diameter
3. Large: 4 in. (~100 mm) equivalent diameter

Using a validated computer model (e.g., Trace®)[1] and meteorological and metocean data (for offshore facilities), the safety impact of the incidents can be determined.

Release Modeling – Liquid, Gas, Two-Phase

Materials handled and treated in the infrastructure are found in different phases and with various physical properties. In general, release models are grouped into three types: 1) liquid release, 2) gas release, and 3) two-phase release. Many fluid mechanics textbooks provide formulae for liquid and gas discharge models.[2,3] Regarding two-phase flow through an opening, Woodward provides empirical models.[2]

Liquid Release Model

The simplest type of a release calculation is a liquid release. When a subcooled liquid whose temperature is below its boiling point (e.g., crude oil stored in a tank) is released, a pool of liquid will form. There is a possibility of surface evaporation for such a liquid pool if enough "light" materials exist in the composition. However, the most probable outcomes of such an event are pollution and a pool fire. The size and depth of a pool are defined by the geology of the corridors and areas surrounding the point of release.

Gas Release Model

The inventory of the gas in process systems is usually limited. This limitation is often from action taken to close upstream and downstream isolation valves once a release is detected, but can also be due to a limited inventory of fluids in the system. Hence, upon an accidental release of a vapor, the pressure of the process system decreases rapidly from the initial contained pressure to atmospheric. The release rate is dependent on several factors, including the hole size, process conditions, and physical properties of the stream. The size of the hole subjects gas flow through an opening to a choked phenomenon. Once a certain differential pressure between the process system and the atmosphere is reached, the flow rate of the gas through the opening is limited regardless of whether there is a further increase in the differential pressure across the release point. Using a time-dependent release model, the team will calculate the discharge rates for the vapor streams associated with gas releasing incidents. Vapor release would contribute to the following incident outcomes: jet fires, flash fires, and vapor cloud explosions.

Two-phase Release Model

Two-phase release (flashing liquid) is difficult to quantify and often empirical models are used.[2] They are the most dangerous type of release because they have the potential to contribute to incident outcomes listed for both vapor and liquid releases—vapor cloud explosions, jet fires, flash fires, pool fires, as well as pollution. Incidents resulting in NGL releases would be modeled using a two-phase release calculation. NGL products contain some lighter ends such as propane and butane that would flash upon a release. For example, when propane is released, approximately 70% of it turns into heavier-than-air vapor, and the rest rains out (drops on the ground) and forms a pool of volatile liquid, which then evaporates and joins the cloud. As a conservative assumption, the team will assume that all liquid turns into a jet of vapor with no rainout for modeling impacts.

Most of the incident outcomes associated with a dense (heavier-than-air) gas cloud are the same as with gas. Another likely incident outcome is a vapor cloud explosion, which could occur when a dense gas finds a congested area (e.g., process plants or parking area) and forms an explosive mixture with air. Such a mixture when ignited can generate an explosion with potential severe impacts.

D-2 Dispersion Analysis

Process equipment and pipelines operate under high pressures; hence, a release can have the characteristics of momentum-dominated jets. For light gases, such as methane, the release gas disperses a medium distance from the source, in particular when the atmospheric conditions are turbulent. There is a slight chance the light gas accumulates and turns into a flash fire (no outdoor explosion) or finds a confined space for a possible indoor explosion. The behavior of light gases is predicted using the Gaussian (normal) model.[4]

For heavier-than-air gases, including flashed vapor due to a release of light ends from NGL, the gas plume initially slumps onto the ground and then disperses under ambient conditions. Several models, including Trace®1, have been developed for this type of release. Several factors influence the trajectory of the plume after a release, including wind speeds and direction, atmospheric stability, and the surface roughness of the surrounding around. In general, the calmer the weather and/or the lower degree of obstructions, the farther a plume is transported.

D-3 Safety Hazard Zone Estimation

Once a hydrocarbon process material is released and dispersed, the next step is to determine the hazardous area (to human safety) if the released material is ignited. As discussed, ignition of the HC release results in one of the following: a flash fire, a pool fire, a jet fire, a vapor cloud explosion, or a confined space explosion.

Flash Fire Model

The prime reason for the dispersion modeling is to calculate the distance to the upper and lower flammability limits of the gas. An example of this is shown in Figure D-1. This is a plume of a natural gas release from a 2-inch. (equivalent diameter) hole in equipment operating at 800 psig. Typical daytime meteorological conditions are assumed. Figure D-1 shows the plume distance to ½ LEL (25,000 ppm), LEL (50,000 ppm), and UEL (150,000 ppm) of a natural gas release. It should be noted that unless the source is unlimited, the plume distance tapers off after a short period of time. In other words, the release of a gas is significantly time dependent. In terms of impacts, the area within the LEL concentration represents a flash fire area with 100% fatality rate.

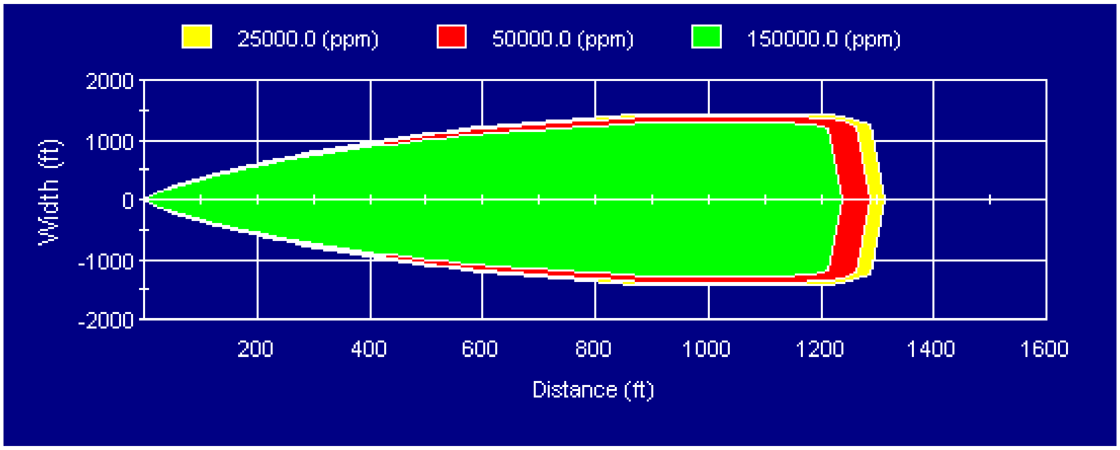

Figure D-1 Example of a Plume Resulting from Natural Gas Release

Pool Fire Model

Spill of oil or another flammable liquid into the surrounding area may create a pool that, upon ignition, will burn and pose thermal flux threat to safety. Large pool fires burn at a constant rate, which is about 0.05 kg/m^2/s. Figure D-2 shows the thermal radiation level resulting from a burning pool of a flammable material. Referring to Figure D-2, the thermal flux is 57 kW/m^2 at up to 25 ft away from the fire source and at about 50 ft, the thermal flux is 20 kW/m$^{2.}$ This radiation intensity can pose a 1% mortality rate for 20 seconds, 50% for 40 seconds, and 98% for 100 seconds exposure.

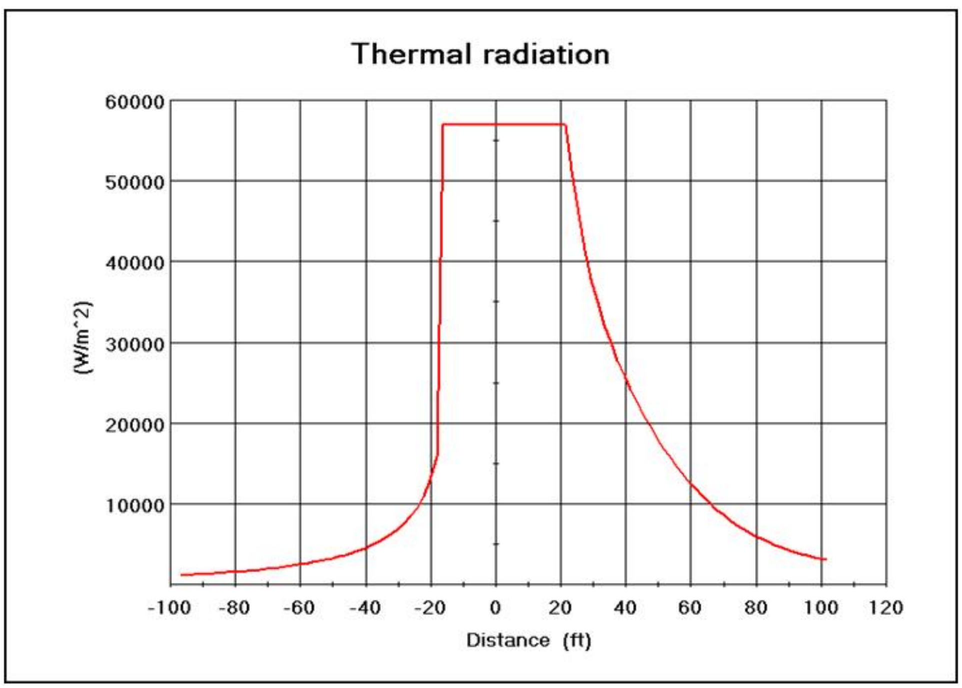

Figure D-2 Example of Pool Fire Thermal Radiation of Crude Oil Pool Fire

Jet Fire Model

An immediate ignition of a release of gas from a hole in equipment can lead to a jet fire. Like a pool fire, the radiant heat from a jet fire could pose a threat to safety. Jet fires could potentially happen at any point in a gas pipeline or pressure vessel due to an accident. Figure D-3 shows the thermal radiation function of distance from the source of the selected release. The source of the release is an opening equivalent to a 4-in. diameter hole in a pressure vessel containing flammable gas.

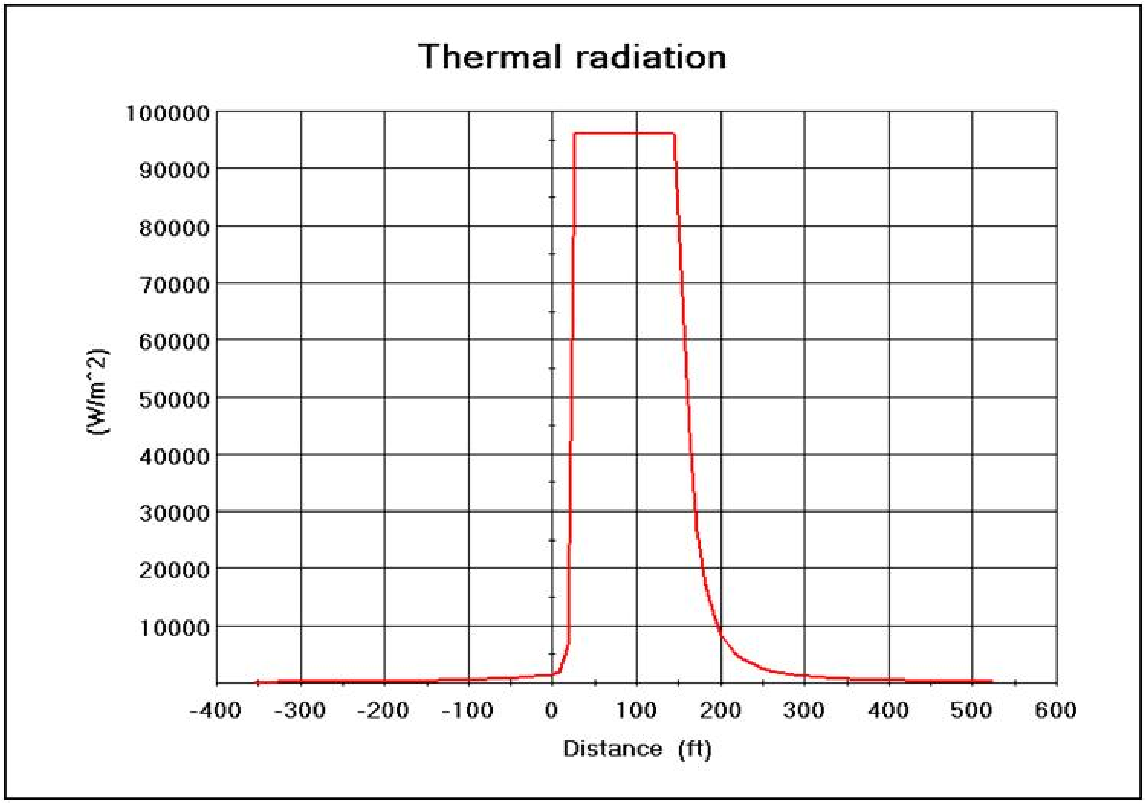

Figure D-3 Example of Jet Fire Thermal Radiation vs. Distance

Vapor Cloud Explosion (VCE) Model

Once a large quantity of a heavy gas (e.g., propane) is released, certain conditions must exist to result in a vapor cloud explosion. These conditions include formation of a large, but well-mixed, flammable vapor cloud and a delayed ignition. Existence of some obstacles, which cause turbulence and hinder dispersion, can create a congested condition favoring a vapor cloud explosion (VCE). Delayed ignition between 1 to 5 minutes can result in a VCE or a flash fire if the conditions are right. In practice, the likelihood of a VCE is much lower than a flash fire. There is also the third possibly of no ignition where the cloud disperses into the atmosphere.

The consequence of a VCE is generally a deflagration, which produces blast pressure effects, but less severe pressure effects than a detonation. Based on the dimension of a congested area, the resultant explosion is depicted in Figure D-4. As shown, the side-on overpressure decays with distance from the pressure source. For example, at about 200 ft the overpressure is 2 psi and at 500 ft the overpressure is about 0.75 psi.

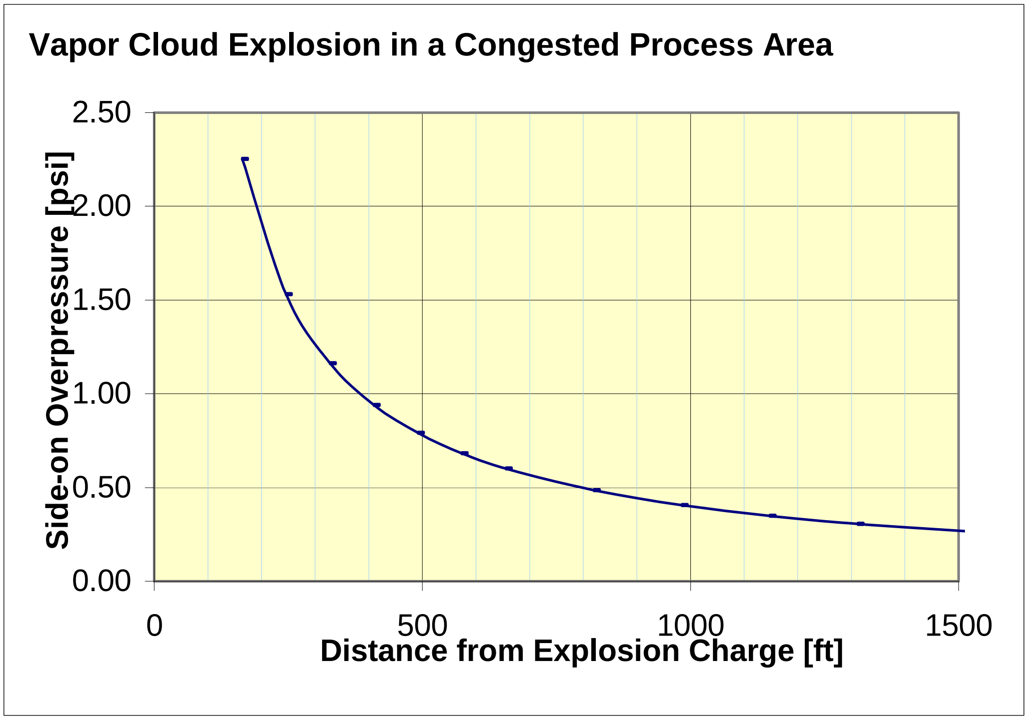

Figure D-4 Example of VCE Overpressure vs. Distance

Confined Space Explosion Model

Accumulation of flammable gas in a confined space creates an explosive condition with potential destructive impacts. It is possible to apply computational fluid dynamic (CFD) software, such as FLACS, to model the potential impacts of such conditions if warranted.

D-4 Impact Modeling

For safety risk, there are two major impacts of concern: 1) thermal radiation safety impacts from fires and 2) overpressure safety impacts due to explosions. This section will discuss modeling these impacts.

Probit Method

The probit method will be used to determine the thermal and overpressure impacts on humans. In general, the probit relation takes the form of Equation D-2:[5]

$$Y = k_1 + k_2 \ ln V$$

Equation D-1 Probit Equation

Where,

V = Causative factor

Y = Probit Variable

Once the causative factor is known, the probit factor is calculated. From the standard probit vs. probability relation, the probability of fatality due to thermal radiation or overpressure can be calculated. The following sections describe these causative factors.

Thermal Impact

Fatal injuries may result from exposure to thermal radiation for some period of time. The product of thermal radiation intensity and time is known as thermal dose. Thermal dose (causative factor) is defined by the empirical Equation D-2,[5]

$$L = t * I^{4/3} / 10^4$$

Equation D-2 Thermal Dose Equation

Where:

L	=	Thermal dose [s(kW/m^2)]
I	=	Thermal radiation intensity [*kW/m^2*]
t	=	Exposed time [s]

Equation D-3 represents the probit model for thermal impact

$$Y = -14.9 + 2.56\, ln\, L$$

Equation D-3 Probit Model for Thermal Impact

By calculating *Y* for various thermal doses, the probabilities of fatalities due to thermal impact can be calculated.

Overpressure Impact

The physiological effects of explosion overpressures depend on the peak overpressure that reaches the person. If the person is far enough from the edge of the exploding cloud, the overpressure may be incapable of directly causing fatal injuries, but still may indirectly cause a fatality. For example, a blast wave may collapse a structure that falls on a person. The fatality is a result of the explosion even though the overpressure that caused the structure to collapse would not directly result in a fatality if the exposed person were in an open area.

In the event of a VCE, the overpressure levels necessary to cause injury to the public are typically defined as a function of peak overpressure without regard to exposure time. Persons who are exposed to explosion overpressures have no time to react or take shelter; thus, time does not enter into the relationship. The causative factor for overpressure is the impulse I, (the integral of the overpressure during the positive phase). Equation D-4 represents the probit relation for death from overpressure impact:[5]

$$Y = -46.1 + 4.82\, ln\, I$$

Equation D-4 Probit Relation to Death from Overpressure Impact

Where:

I = Impulse in kPa-s

By calculating *Y* in Equation D-4 for various impulse levels, the probabilities of fatalities due to overpressure impact can be calculated.

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Appendix E. Bayesian Method for Data Enhancement Methodology

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Equipment failure rate updating—Bayesian estimation

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Abstract

The paper presents a Bayes' method for augmenting generic equipment failure data with a prior distribution – predicated on the evidence, e.g., plant data – resulting in a posterior distribution. The depth of the evidence is significant in shaping the characteristics of the posterior distribution. In conditions of insufficient data about the prior distribution or great uncertainty in the generic data sources, we may use "constrained non-informative priors". This representation of the prior preserves the mean value of the failure rate estimate and maintains a broad uncertainty range to accommodate the site-specific event data. Although the methodology and the case study presented in this paper focus on the calculation of a time-based (i.e., failures per unit time) failure rate, based on a Poisson likelihood function and the conjugate gamma distribution, a similar method applies to the calculation of demand failure rates utilizing the binomial likelihood function and its conjugate beta distribution.
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Keywords: Bayes' theorem; Failure rate; Prior distribution; Posterior distribution; Poisson distribution; Gamma distribution; Conjugate gamma distribution

1. Introduction

The well-established quantitative risk analysis methodology [1] begins with the task of hazard analysis (e.g., HAZOP) in which potential hazardous events (scenarios) are identified. The scenarios provide the answer to the question of "what could happen?" There are other questions still need responses: "how often?" and "what is the impact?" Each scenario has two dimensions frequency and consequence. The risk of each scenario – to certain population, the environment or the asset – is the product of frequency and severity of consequence associated with the scenario. The total risk posed by the plant is therefore the integration of the scenario risks. Garrick and Kaplan in a classic paper [2] provide a quantitative definition of risk in terms of the idea of a "set of triplets". The definition is extended to include uncertainty and completeness, and the use of Bayes' theorem is described in this connection. The definition is used to discuss the notions of relative risk, and acceptability of risk.

Equipment failure rates are a main ingredient in any risk or reliability analysis. In a risk analysis, the failure data is needed to estimate the frequencies of events contributing to risks posed by a facility. And in a reliability analysis, they are required to predict an unavailability or unreliability of a system. But, the question is where are we going to get the data from? There are two sources of hard data: data collected at a facility – "plant specific" – and data reported by industry – "generic" data. One of the sources of plant specific data is work orders. Unless it is designed for the purpose, work orders are inherently inconsistent and in some cases convoluted.

Now suppose you are conducting a risk assessment study of a plant, which consists of, say, 13 pressure vessels among other equipment items and it has been in operation for 10 years. To dramatize the situation let us assume that the plant has zero number (or any number) of pressure vessel failure (of any kind) since the startup. In other words the plant has zero failure in 130 pressure-vessel-years. Now, is it justifiable to use this information for estimating the risk associated with the pressure vessels at this plant?

Generic data, which are publicly available, e.g., for the chemical process industry [3], for the nuclear industry [4], and for the offshore installation [5], which represent a cross-section of industry. From statistical point of view, most of these sources will provide you with valid point estimates and occasionally lower and upper bound values. However, generic data suffers a major shortcoming, which is non-specific.

Although both approaches provide you with some estimates, neither could produce representative equipment failure frequencies. This is because plant specific data is statistically invalid

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due to a short duration of data collection or limited population of equipment. Generic data, on the other hand, does not reflect the characteristics and conditions of the plant that the equipment is operated under. Hence the use of plant specific or generic data would not to help estimate realistic risk or reliability of a plant.

There is a third way, which is often known as data augmentation, which is performed using the Bayesian methodology. In this approach we use generic data as *a priori* and plant specific data as an evidence (likelihood) to obtain posterior.

2. Bayesian updating methodology

Bayesian statistics is based on the subjective definition of probability as 'degree of belief' and on Bayes' theorem, the basic tool for assigning probabilities to hypotheses combining a prior judgments and experimental information [6].

The approach presented is known as two-step Bayesian methodology [7]. There are many sources of information on Bayes' theory and applications. The two outstanding books by Winkler [8] and Janes [9] are among the best sources of Bayes' theorem. Winker's is on inference and decision making while Janes' book has been the trademark of Bayesian methodology in the risk community.

The approach consists of three main tasks, as follows:

1. Define a prior distribution for the equipment failure rate.
2. Gather evidence, known as the likelihood function.
3. Construct the posterior distribution using Bayes' theorem.

In the context of failure rate estimation, the Bayes' theorem is presented in a functional relationship, as follows:

$$f_{\text{post}}(\lambda) \propto \text{likelihood}(\lambda) f_{\text{prior}}(\lambda) \tag{1A}$$

or

$$f_{\text{post}}(\lambda) \propto Pr(X = x|\lambda) f_{\text{prior}}(\lambda) \tag{1B}$$

where λ = equipment failure rate; $f_{\text{prior}}(\lambda)$ = posterior distribution of failure rate (λ); likelihood (λ) = likelihood function of failure rate (λ); $\Pr(X = x|\lambda)$ = likelihood function as function of λ, for given failure event (x); $f_{\text{post}}(\lambda)$ = posterior distribution of failure rate (λ).

The choice of the prior distribution signifies the analyst's state of knowledge regarding the equipment failure rate. The prior distribution may be derived from a single source, or from a collection of available sources. In failure rate estimation, often generic data is used as the basis for the prior distribution. In case hard data is not available or not from a reputable source, expert opinions may be used to define a prior. Expert opinion is acquired by special techniques such as the Delphi method [10].

Evidence is based on the statistics collected at a specific facility. If the evidence were too limited, then the posterior would resemble the prior. It is significant to remember that the evidence must be independent of the prior. As the historical data becomes larger, several patterns emerge [15]:

- The posterior distribution bears less resemblance to the prior distribution, because the data become the dominant factor.
- The posterior would be narrower and centered around maximum likelihood estimate, implying less uncertainty in the results.

2.1. Choice of prior distribution and likelihood function

Let us first start with the likelihood function, which is best defined by the Poisson distribution defining the behavior of the facility failure data. This is an appropriate distribution for random variables that involve counts or events (such as pressure vessel failure) per unit time.

The Poisson distribution is presented below:

$$Pr(X = x|\lambda) = \frac{e^{-\lambda t}(\lambda t)^x}{x!} \tag{2}$$

where x = number of events (failures); t = time interval.

The conjugate family of prior distributions for Poisson data is the family of gamma distributions. That is to say the uncertainty of the failure rate (λ) is defined by the gamma distribution. The gamma distribution and the event data can be combined to result in another gamma distribution. This is the meaning of the conjugate family.

In the context of Bayes' theorem, when we choose the gamma distribution for the prior, updating it by the Poisson likelihood model, then the posterior distribution is also constructed by the gamma distribution.

The gamma distribution for the prior with two parameters of scale factor (α) and the shape factor (β), which is shown below:

$$f_{\text{prior}}(\lambda) = \frac{\beta^{\alpha}}{(\alpha - 1)!} \lambda^{\alpha-1} e^{-\lambda\beta} \tag{3A}$$

Expression (3A) can also be presented as:

$$f_{\text{prior}}(\lambda) \propto \lambda^{\alpha-1} e^{-\lambda\beta} \tag{3B}$$

Note that this expression is valid only when α takes a positive value.

This is known as the gamma (α,β) distribution, where the mean and variance are defined as follows:

$$\text{Mean}\ (\lambda) = \frac{\alpha}{\beta} \tag{4}$$

$$\text{Variance}\ (\lambda) = \frac{\alpha}{\beta^2} \tag{5}$$

2.2. Posterior distribution

Using the gamma distribution for the prior and Poisson for the likelihood, the updated distribution is also a gamma distribution. The resulting posterior distribution, which is a combination of the prior gamma distribution and Poisson distribution for the likelihood function, is also the gamma distribution, given in Eq. (4), which defines conjugate:

$$f_{\text{post}} \propto e^{-\lambda t} \frac{(\lambda t)^x}{x!} \lambda^{\alpha-1} e^{-\lambda\beta} \tag{6A}$$

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Simplified further, results in:

$$f_{\text{post}} \propto \lambda^{(x+\alpha)-1} e^{-\lambda(t+\beta)} \tag{6B}$$

The posterior gamma distribution parameters are simply calculated by the following equations:

$$\alpha_{\text{post}} = x + \alpha_{\text{prior}} \tag{7}$$

$$\beta_{\text{post}} = t + \beta_{\text{prior}} \tag{8}$$

Eqs. (7) and (8) along with Eq. (4) (the mean) are the primary tools for the Bayesian update in this study.

Based on Atwood's [17] priors, for Poisson data, the constrained non-informative prior is a gamma distribution with the shape factor and scale factor of the following values:

$$\alpha_{\text{prior}} = \frac{1}{2} \tag{9}$$

$$\beta_{\text{prior}} = \alpha_{\text{prior}}/\text{prior mean} \tag{10A}$$

$$\beta_{\text{prior}} = 1/2\,(\text{prior mean}) \tag{10B}$$

Given the best estimate for mean value of failure rate (from generic data), then the parameters of the gamma prior distribution, α_{prior} and β_{prior}, will be calculated according to Eqs. (9), (10A) and (10B).

3. Case study

The remainder of this paper focuses on the use of the methodology described above to estimate pressure vessel failure rates for several failure modes.

3.1. Prior distribution

Once the prior distribution is known it is required to estimate its parameters, e.g., the mean value. The quality and quantity of generic data as well as the analyst's preference dictate the method of generating the parameters. The analyst may have access to a single or multiple credible data sources. In the multiple source case, the analyst may simply choose to select the most reliable, or employ one of a number of methods to merge these data into a single point estimate. The methods range from calculation of an arithmetic mean to the use of sophisticated Bayesian procedures [11].

For the purpose of this analysis, we have searched various generic data sources applicable to pressure vessels; the results are given in Table 1. The mean values in Table 1 are taken directly from the referenced data sources given in the table. The data includes "disruptive" and "no-disruptive" failure modes. The definitions of the terms used in Table 1 are given below:

- Disruptive failure—"a breaching of the vessel by failure of the shell, head, nozzles or bolting, accompanied by a rapid release of the large volume of the contained pressurized fluid" [12].
- Non-disruptive failure—"a condition of crack growth rate or flaw size that is corrected, and which if it had not been corrected, could have reached a critical size and led to disruptive vessel failure" or "a local degradation of the pressure vessel boundary that is localized cracking with or without minor leakage. Such a crack would not reach critical size and lead to disruptive vessel failure" [12].
- Range factor—the range factor implies the level of confidence that the analyst has in the data source. The smaller the range factor, the higher the confidence of the analyst in the data source. For the gamma distribution, the range factor can be estimated by the square root of the ratio of the 95th percentile value to the 5th percentile value.

Based on the analyst's (the author's) level of confidence in each source, a range factor and a probability (weight) have been assigned to each source in Table 1. The data reported by Bush has received a small range factor, relative to the other sources, because of the analyst's high level of confidence in this source. On the other hand, data reported in Rijnmond report was assigned a range factor of 9, indicating a lower level of confidence in this data source. The probability weights also represent the analyst's confidence in each data source.

Using the data given in Table 1, we have calculated prior distribution mean values (Table 2) using different method for comparison purposes. In this study we will use the mean values calculated using weighted average method.

Table 1
Pressure vessel failure mode generic data and assigned range factors and probabilities

Source	Disruptive (per year)	Non-disruptive (per year)	Assigned range factor	Weight factors[b]
Savannah River Site [13]	3.33E−04	3.24E−03	7	0.05
EEI-TVA [12]	3.00E−04	1.70E−03	4	0.08
EEI Boiler Drum [12]	1.40E−04	2.00E−04	4	0.08
Chemical [14]	5.48E−05	1.05E−04	3	0.11
UK Steam Drum Sample [12]	5.00E−05	6.00E−04	3	0.11
IRS-TUW [12]	4.50E−05	6.00E−04	3	0.11
NBBPV [12]	3.50E−05	–[a]	3	0.11
UK-Smith& Warwick [12]	3.20E−05	2.60E−04	4	0.08
CCPS [3]	9.55E−06	5.57E−05	5	0.07
German LWR Study Group [13]	8.80E−06	–[a]	4	0.08
ABMA [13]	4.20E−06	–[a]	4	0.08
Rijnmond [16]	1.00E−06	1.00E−05	9	0.04

[a] These sources have reported no frequencies for the non-disruptive.
[b] Weight factors are calculated using ranged factors and are normalized.

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Table 2
Calculated prior distribution mean values for pressure vessel failure modes (alternate methods)

Method of calculation	Disruptive (per year)	Non-disruptive (per year)
Arithmetic mean (average)	8.40E−05	7.50E−04
Geometric mean	3.10E−05	4.10E−03
Weighted average[a]	**7.70E−05**	**4.80E−04**
Bayesian [7]	6.70E−05	6.00E−04

[a] Used in the case study.

Using the data given in Table 1, we have calculated prior distribution mean values (Table 2) using different method for comparison purposes. In this study we will use the mean values calculated using weighted average method.

3.2. Plant specific data

A hypothetical case is used to demonstrate the data analysis method presented in this paper. Consider company XYZ, a worldwide gas and oil firm, has collected pressure vessel failure data for their facilities for the past 15 years. The number of pressure vessels in operation is 187. The history has shown zero disruptive and seven non-disruptive failures for the past 15 years among the 187-pressure vessel population. Table 3 shows the evidence that will be used to update the generic data (prior).

3.3. Data updating

Using the constrained non-informative gamma distribution [15], the parameters of the prior distribution for the disruptive pressure vessel failure mode are calculated as follows:

$$\alpha_{\text{Prior}}^{\text{Dis}} = 0.5$$

$$\beta_{\text{Prior}}^{\text{Dis}} = 0.5/7.7E-05 = 6536$$

The posterior gamma distribution parameters are calculated:

$$\alpha_{\text{Post}}^{\text{Dis}} = 0 + 0.5 = 0.5$$

$$\beta_{\text{Post}}^{\text{Dis}} = 15 \times 187 + 6536 = 9341$$

The posterior mean is then calculated as:

$$\lambda_{\text{Post}}^{\text{Dis}} = 0.5/9341 = 5.4E-05$$

(events per year; disruptive failure mode)

Following the same steps for non-disruptive failure mode, we would get the following mean value for posterior distribution of the non-disruptive failure mode:

$$\lambda_{\text{Post}}^{\text{N-Dis}} = 2.0E-03$$

(events per year; non-disruptive failure mode)

Table 4 presents calculated distribution parameters of disruptive and non-disruptive pressure vessel failure modes for the example.

Table 3
Plant specific data for the case study

Poisson parameters	Disruptive	Non-disruptive
X (number of failures)	0	7
t (time interval)	15	15

Table 4
Prior and posterior parameters for pressure vessel failure modes

Gamma distribution parameters	Disruptive		Non-disruptive	
	Prior	Posterior	Prior	Posterior
α	0.5	0.5	0.5	7.5
β	6536	9341	1048	3853
λ (per year)	7.70E−05	5.40E−05	4.80E−04	2.00E−03
5th percentile (per year)	4.40E−05	3.10E−05	2.10E−05	9.20E−04
95th percentile (per year)	2.70E−04	1.90E−04	1.70E−03	3.20E−03

4. Conclusions

The method starts with a prior distribution, which must come from sources independent from the subject plant under study. An appropriate source is generic data reported in the literature or used in other studies. The issue with data reported in the literature is that it is mostly incomplete and often presented in terms of "point estimates", which are single values representing the mean (or median) of the failure rate.

The depth of the evidence, e.g., plant data, is significant in shaping the characteristics of the posterior distribution. As shown in the case study, due to lack of disruptive failure at the plant the posterior mean (5.40E−05) is very close to that of the prior (7.70E−05). In comparison, the number of non-disruptive failure was relatively large, hence the difference between the prior and posterior means are almost an order of magnitude.

In conditions of insufficient data (incomplete prior knowledge) about the prior distribution or great uncertainty in the generic data sources, we may use "constrained non-informative priors" described by Atwood [17]. This representation of the prior preserves the mean value of the failure rate estimate and maintains a broad uncertainty range to accommodate the site-specific event data.

Although the methodology and the case study presented in this paper focus on the calculation of a time-based (i.e., failures per unit time) failure rate, based on a Poisson likelihood function and the conjugate gamma distribution, a similar method applies to the calculation of demand failure rates utilizing the binomial likelihood function and its conjugate beta distribution.

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Appendix F. Pipeline Scoring System

Table F-1 Operating and Maintenance Index

Operating and Maintenance Index	
Constructions	
Inspection	0-10 pts
Materials	0-2 pts
Joining	0-2 pts
Backfill	0-2 pts
Handling	0-2 pts
Coating	0-2 pts
	0-20 pts
Operation	
Procedure	0-7 pts
SCADA/Communications	0-5 pts
Drug-Testing	0-2 pts
Safety Programs	0-2 pts
Surveys	0-2 pts
Training	0-10 pts
Mechanical Errors Preventers	0-7 pts
	0-35 pts
Maintenance	
Documentation	0-2 pts
Schedule	0-3 pts
Procedures	0-10 pts
	0-15 pts

Table F-2 Design and Construction Index

Design and Construction Index	
Hazard Identification	0-4 pts
MAOP Potential	0-12 pts
Safety System	0-10 pts
Material Selection	0-2 pts
Checks	0-2 pts
	0-30 pts

Table F-3 Corrosion Index

Corrosion Index	
Atmospheric corrosion	
Facilitates	0-5 pts
Atmosphere	0-10 pts
Coating/Inspection	0-5 pts
	0-20 pts
Buried Metal Corrosion	
Cathodic Protection	0-8 pts
Coating Condition	0-10 pts
Soil Corrosivity	0-4 pts
Age of system	0-3 pts
Other Metals	0-4 pts
AC Induced Current	0-4 pts
Mechanical Corrosion	0-5 pts
Test Leads	0-6 pts
Close Internal Survey	0-8 pts
Internal Inspection tool	0-8 pts
	0-60 pts
Internal Corrosion	
Product Corrosivity	0-10 pts
Internal Protection	0-10 pts
	0-20 pts

Table F-4 Third-party Index

Third-party Index	
Minimum Depth of Cover	0-20 pts
Activity Level	0-20 pts
Aboveground Facilities	0-10 pts
One-Call System	0-15 pts
Public Education	0-15 pts
Right of way Condition	0-05 pts
Patrol Frequency	0-15 pts
	0-100 pts

Appendix G. Environmental Consequences Calculation Example Scenarios

Table G-1 Environmental Consequences Calculation Example Scenarios (State of Alaska Subarea Contingency Plans Scenarios and Regional Historical Spills)

Material Composition Index	Environmental Sensitivity Category Index	Release Quantity Index	Recoverability/ Remediation Index	Rev. 1 Environmental Consequence Score	Rev. 0 Environmental Consequence Score	State of Alaska Regional Contingency Plan Scenarios (Appendix B) and ADEC Database Reports for Top Regional Spills	Material	Volume (bbl)
M	S	Q	R	N	N			
1 - 3	1 - 3	4 - 6	1 - 3					
3	3	6	1	45	45	Well Blowout spill to ocean of 5,000 BBLs/day for 60 days. (NS)	Crude	300,000
3	3	6	1	45	45	Tanker spill to ocean. (CI)	Crude	380,000
3	3	6	1	45	45	Tanker spill to ocean. (PWS)	Crude	2,200,000
3	3	6	1	45	45	Kuparuk pipeline spill to Kuparuk River. (NS)	Crude	10,516
3	3	6	1	45	45	TAPS spill migrating to river. (I)	Crude	49,450
3	3	6	1	45	45	TAPS spill migrating to river. (PWS)	Crude	40,000
3	3	6	1	45	45	Well Blowout spill to ocean of 5,000 BBLs/day for 60 days. (CI)	Crude	300,000
3	3	6	1	45	45	Tanker (Exxon Valdez) spill to ocean. (PWS)	Crude	257,000
3	3	5	1	36	36	1976 USNS Sealift Pacific (CI)	Jet A	9,420
3	3	5	1	36	36	1987 T/V Glacier Bay (CI)	Crude	5,000
3	3	5	1	36	36	1989 T/V Thompson Pass (PWS)	Crude	1,786
3	3	4	1	27	27	Barge spill to ocean. (NS)	Diesel	500
3	3	4	1	27	27	Vessel transfer spill to ocean. (CI)	Diesel	50
3	3	4	1	27	27	Vessel transfer spill to ocean. (PWS)	Diesel	25
3	3	4	1	27	27	1994 T/V Eastern Lion (PWS)	Crude	200
3	2	5	2	18	18	Pipeline spill to wetlands. (CI)	Crude	2,400
3	2	5	2	18	18	Oil Transit Pipeline spill to tundra between Gathering Centers. (NS)	Crude	4,800

Material Composition Index	Environmental Sensitivity Category Index	Release Quantity Index	Recoverability/ Remediation Index	Rev. 1 Environmental Consequence Score	Rev. 0 Environmental Consequence Score	State of Alaska Regional Contingency Plan Scenarios (Appendix B) and ADEC Database Reports for Top Regional Spills	Material	Volume (bbl)
M	S	Q	R	N	N			
1 - 3	1 - 3	4 - 6	1 - 3					
						between Gathering Centers. (NS)		
3	3	4	2	18	18	Rail tanker spill migrating to River. (I)	Jet A	595
3	3	4	2	18	18	Tanker truck spill migrating to River. (I)	Gasoline	24
3	3	4	2	18	18	Tanker truck spill migrating to River. (PWS)	Diesel	190
3	2	5	2	18	18	1981 TAPS Check Valve 23 (NS)	Crude	2,000
3	2	6	2	24	12	1978 TAPS MP 474 Steele Creek (I)	Crude	16,000
3	2	5	2	18	9	2001 TAPS Bullet Hole Spill (I)	Crude	6,800
3	2	4	1	18	6	TAPS check valve (reference CV-92) spill underground. (PWS)	Crude	710
3	2	4	2	12	12	Transportation spill to wetlands. (CI)	Diesel	48
2	2	5	2	12	12	2001 Kuparuk CPF1 to DS 1B (NS)	PW	2,200
3	2	4	3	6	6	1989 CPF Milne Point (NS)	Crude	925
Screened-Out Due to Volume						Vessel transfer spill to ocean. (NS)	Diesel	1.2
Screened-Out Due to Volume						Haul road truck spill to tundra. (NS)	Diesel	6.3
Screened-Out Due to Volume						Refinery tank overfill spill to uplands. (CI)	Oil	0.3

NOTE 1: LIMITED SUMMARY DATA WAS REVIEWED IN THE DEVELOPMENT OF THIS TABLE AND SCORING IS DRAFT IN LIEU OF DETAILED SCENARIO OR INCIDENT RECORDS REVIEW. THESE SCENARIOS ARE INCLUDED FOR TESTING AND ILLUSTRATION PURPOSES ONLY AND DO NOT NECESSARILY REPRESENT INCIDENTS WHICH ARE IN THE SCOPE OF THE ARA OR WILL BE EVALUATED DURING THIS ASSESSMENT.

Note 2: (CI) = Cook Inlet Region; (I) = Interior Region, (NS) = North Slope Region; (PWS) = Prince William Sound Region

Appendix H. Quantitative Availability Approach for Reliability Risk

Availability Analysis Terminology

The following terms are defined to help understand the tasks described in the methodology.

Equipment mean-time-between-failures (*MTBF*)

This is the average time between occurrences of a specific failure mode of equipment, which is the inverse of the equipment failure rate (for that mode of failure) and is shown as Equation H-1.

$$MTBF_x = 1/\lambda_x$$

Equation H-1 Equipment Failure Mode

Where the dimension of the *MTBF* is time (e.g., years) and:

λ_x = Equipment failure rate

x = A specific failure mode

Example: If a failure rate, λ_x, is one failure in 25 years, then *MTBF* is 25 years.

Equipment mean-time-to-restoration (MTTR)

This is the average time to restore equipment operation (includes time to detect failure, diagnose problem, repair, and return to operation) and is shown as Equation H-2.

$$MTTR_x = 1/\theta_x$$

Equation H-2 Time Required to Restore Equipment to Operation

Where the dimension of the *MTTR* is time (e.g., days or hours) and:

θ_x = Equipment restoration rate

x = A specific failure mode

Example: If the equipment restoration rate is one in 24 hours, then *MTTR* is 24 hours, or 0.066 years. *MTTR* is typically a very small number compared to *MTBF*.

Equipment Availability (uptime) (A)

The steady state (long-term) equipment availability (*A*) is the fraction of time that the equipment is up and functioning, which is expressed as Equation H-3:

$$A = MTBF/(MTBF + MTTR)$$

Equation H-3 Equipment Availability (Uptime)

Example: For a MTBF of 25 years and MTTR of 0.066 years, the availability is:

A = 25 / (25 + 0.066)
A = 0.99737

Equipment Unavailability (downtime) (U)

Equipment unavailability downtime is defined as Equation H-4:

$$U = 1 - A$$

Equation H-4 Equipment Unavailability (Downtime)

Where A is Equipment Availability (uptime) and is found using Equation H-3.

Example: For the case above, the unavailability is:

$U = 1 - 0.99737$
$U = 0.00263$ or 2.63×10^{-3}

System Availability and Unavailability

System availability and unavailability are calculated based on the configuration of the equipment comprising the system and any redundancies incorporated into the system design.

Estimating MTBFs and MTTRs

For the nodes that passed the preliminary screening and have potentially significant reliability consequences, the FMEA process will produce a list of significant equipment and their failure modes. Two key characteristics (*MTBF* and *MTTR*) of equipment and their failure modes will be estimated using the following data:

1. Facility Owner/Operator Operational Experience
2. Facility Owner/Operator Historical Data
3. Generic Industry-wide Data Sources

It will be important to meet with the facility owners/operators as operational experience and historical data will need to be provided by the facility owners/operators. This includes information regarding how long it will take the facility owners/operators to repair a certain component that fails and historical availability (uptime) figures. For example, if a major compressor were to fail, only the facility owners/operators could provide reasonable data regarding how quickly a new part or equipment repair could be acquired and installed for start-up and at what cost. Once again, the project team will employ the Bayesian approach described in Appendix E to augment generic industry-wide data with facility-specific operational and historical data.

RBD-based System Availability Analysis

Given the reliability block diagram (RBD), system availability is computed by translating the block diagram to a set of Boolean equations, followed by a Monte Carlo simulation that uses the subsystem *MTBF* and *MTTR* estimates.[1] The Monte Carlo simulation will iterate through the system level computations many times to build a statistical profile of the system availability/ unavailability estimates. Each pass through the computations begins with a random start of the clock, which in turn exercises the system at various points in time. Care must be taken to allow enough simulation iterations so that results converge. Computer software such as Crystal Ball and @Risk are used to perform the simulation.

[1] *Guidelines for Chemical Process Quantitative Risk Analysis*. New York: American Institute of Chemical Engineers, 1999.

Appendix I. American Lifelines Alliance (ALA) Guidelines

Appendix J. Natural Hazards Assessment Data Requirements

Wells

Table J-1 Natural Hazards Assessment Data Requirements–Wells

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Facility maps and general arrangement drawings
Description of asset	Description of major assets
Vintage of asset	Year placed in service
Design Basis	Design Code for jurisdictional authority (UBC, IBC, etc.)
Design and risk studies	Design basis reports, Post design risk studies
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events and weather.

Gathering Lines

Table J-2 Natural Hazards Assessment Data Requirements–Gathering Lines

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Pipeline system routing map with locations, profiles and geotechnical conditions
Description of asset	Description of pipeline sizes, wall thickness, valving, storage, compressor stations, etc.
Vintage of asset	Year(s) placed in service, material condition program, historical trends and current reports.
Design Basis	Design Code for jurisdiction (API, ANSI, UBC, etc.)
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic and geotechnical reports. Post design risk studies.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events and weather.

Gathering/Processing Facilities and Pump Stations

Table J-3 Natural Hazards Assessment Data Requirements- Gathering/Processing Facilities, Pump Stations (including storage/breakout tanks)

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Facility maps and general arrangement drawings
Description of asset	Descriptions and engineering drawings of process buildings, major facility equipment, vessels, and storage, etc.
Vintage of asset	Year(s) placed in service, material condition program, historical trends and current reports.
Design Basis	Design Codes and specifications for designs (API, ANSI, UBC, etc.)
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic, geotechnical and flood inundation reports. Post design risk studies.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events, weather; flooding, forest fires, foundation problems from erosion, soil movements, subsidence, etc.; design, engineering and monitoring programs for permafrost.
Emergency Plans	Operator emergency plans, monitoring and mitigation programs for avalanche, volcano, forest fires, weather and other hazards.

Pipelines - Above ground, Underground, Submarine

Table J-4 Natural Hazards Assessment Data Requirements–Pipelines (Above ground, Underground, and Submarine)

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Pipeline system routing map with locations, profiles and geotechnical conditions
Description of asset	Description of pipeline sizes, wall thickness, valving, storage, compressor stations, etc., location and design type of river crossings
Vintage of asset	Year(s) placed in service, material condition program, historical trends and current reports
Design Basis	Design Codes and specifications for designs (API, ANSI, UBC, etc.).
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic, geotechnical and flood inundation reports. Post design risk studies.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events, weather; flooding, forest fires, foundation problems from erosion, soil movements, forest fires, underwater currents, subsidence, etc.; design, engineering and monitoring programs for permafrost.
Emergency Plans	Operator emergency plans, monitoring and mitigation programs for avalanche, earthquake, forest fires, and other hazards.

TAPS Pipeline

Table J-5 Natural Hazards Assessment Data Requirements–Taps Pipeline

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Pipeline system routing map with locations, profiles and geotechnical conditions for each pipeline segment.
Description of asset	Description of pipeline sizes, wall thickness, valving, storage, pump stations, electric power and other critical outside utilities, etc. location and design type of river crossings
Vintage of asset	Year(s) placed in service, material condition program, historical trends and current reports
Design Basis	Design Codes and specifications for designs (API, ANSI, UBC, etc.)
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic, geotechnical and flood inundation reports. Post design risk studies. Pipeline curvature monitoring program reports from Geopig inspections.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events, weather, flooding, forest fires, etc,; Denali Earthquake reports; foundation problems from erosion, soil movements, forest fires, subsidence, etc.; design, engineering and monitoring programs for permafrost. Integrity management plan (IMP) annual reports.
Emergency Plans	Alyeska emergency plans, monitoring and mitigation programs for avalanche, earthquake, forest fires, and other hazards.

Marine Loading Facilities

Table J-6 Natural Hazards Assessment Data Requirements–Marine Loading Facilities

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Facility maps and general arrangement drawings
Description of asset	Descriptions and engineering drawings of process buildings, major facility equipment, marine loading piers, and storage, etc. Protective features for natural hazards, dike diversions, seawalls, berms, etc.
Vintage of asset	Year(s) placed in service, material condition program reports.
Design Basis	Design Codes and specifications for designs (API, ANSI, UBC, etc.) for each major portion of the facility, loading piers, equipment, foundations and major modifications and renovations.
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic, geotechnical and flood inundation reports. Post design risk studies.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events. Foundation problems from erosion, currents, soil movements, etc.
Emergency Plans	Operator emergency plans, monitoring and mitigation programs for avalanche, earthquake, volcano and other hazards.

Offshore Production Platforms

Table J-7 Natural Hazards Assessment Data Requirements–Offshore Production Platforms

DATA ATTRIBUTE	FACILITY SPECIFIC DATA
Location	Platform location maps and general arrangement drawings of topsides and base structures.
Description of asset	Descriptions and engineering drawings of topsides, structures, air gap, major equipment, and storage, foundations, etc.
Vintage of asset	Year(s) placed in service, material condition program, historical trends and current reports
Design Basis	Design Codes and specifications for designs (API Recommended Practice, ANSI, etc.) for topside and structure and major modifications and renovations.
Design and risk studies	Design basis reports. Site specific natural hazard studies by the owner, operator or consultants. Site specific hazard (frequency of occurrence and severity) study reports. Site specific geologic and geotechnical reports. Post design risk studies.
Natural hazards event reports and history	Post natural hazard reconnaissance, problems or other reports related to damage from natural hazard events. Wind and current history data (if available).
Emergency Plans	Emergency plans, monitoring and mitigation programs for wind, sea state, ice, earthquake and other hazards.

Appendix K. Natural Hazards Assessment Data Sources

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