DECOMMISSIONING METHODOLOGY AND COST EVALUATION

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"THE RESEARCH PROJECT OUTCOME DID NOT CONCLUDE AS A HIGHLY INFLUENTIAL OR INFLUENTIAL CATEGORY. THEREFORE, BSEE WOULD NOT CONDUCT A PEER REVIEW FOR THIS RESEARCH."

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FACILITIES DECOMMISSIONING AND WELL ABANDONMENT PROCEDURES AND ASSUMPTIONS

1. INTRODUCTION

This report accompanies a cost evaluation model to support setting the bonding requirements for decommissioning and abandonment of an offshore gravel island with associated exploration and/or production oil and gas facilities and pipelines located on the Alaskan Outer Continental Shelf (OCS). The area of focus is limited to the Beaufort Sea where there are existing oil and gas resources under development on federal offshore leases. The report includes an explanation of typical procedures for Arctic facilities decommissioning, well plug and abandonment, and reasonable worst-case scenario assumptions for use in the cost model.

To ensure adequate bond coverage for a generic gravel island installation at an unknown future time and circumstances, the procedures focus on a reasonable worst-case scenario. In many cases there are other more efficient, less costly alternatives; those options may be listed in this report for added perspective, but they are not developed in detail or contained in the cost estimate. Worst-case scenario assumptions used in the cost estimate associated with this report are provided at the beginning of each report section.

The decommissioning and well abandonment study and the cost model included in this report use data from the plug and abandonment procedure for typical offshore wells in the nearshore and offshore Beaufort Sea Alaska operating areas. The facilities decommissioning procedures and associated assumptions have been developed based on previous gravel island abandonment activities and experience gained during installation of existing facilities such as British Petroleum's (BP) Northstar development and the plans for the Liberty development. These data sets combined make up the inputs for the base case full decommissioning scenario.

The information in this report focuses on facilities decommissioning and well abandonment procedures for offshore gravel islands located in areas where the US Bureau of Safety and Environmental Enforcement (BSEE) has regulatory authority. Some associated facilities may be located on the shore on lands where BSEE does not have regulatory control. These onshore facilities will generally be decommissioned under separate procedures and bonding requirements. However, there are some onshore facilities that are integrally connected to offshore decommissioning activities that cannot logically be treated in separate procedures; for example, subsea pipeline abandonment procedures cannot be separated from the decommissioning procedures for the pipeline's onshore terminus and riser. The onshore decommissioning activities in such cases are described within this report. Inter-agency coordination will be necessary for any activities that occur on the shore or in state waters.

1.1. BACKGROUND INFORMATION

In preparing these procedures, information was gathered from a range of historical island decommissioning operations in state and federal waters such as Mukluk, Endicott (Endeavour Island), Resolution, Tern, the original Northstar Island (Amerada Hess), and Seal Island. Some of these islands were constructed islands and some were natural islands that returned to their original state upon decommissioning. Data from current operations including operations such as BP's Northstar development, Oooguruk, and future operations such as Liberty were also included as data sources for the decommissioning procedures and resultant cost model.

Gravel island design over these data sets has consisted of gravel placed during winter operations from floating ice roads followed by installation of slope protection and any other required facilities. Slope protection has included gravel filled polypropylene bags, sheet pile, and linked concrete mats. Facilities have included a single exploration well to full development with multiple wells, production facilities, and extensive subsurface utilities.

Wells on these islands can include exploratory, production, injection, and disposal wells. Well abandonment procedures and assumptions have been derived from regulatory requirements for plug and abandonment of wells on the OCS (30 CFR 250 Subpart Q) and a review of existing and typical exploration, development, and disposal wells in the Beaufort Sea. Table 1-1 (See Appendix A) provides a sample of wells reviewed for procedure preparation and plug and abandonment cost estimation.

1.2. Procedure Overview

Prior to commencing an offshore gravel island decommissioning effort, a permitting and planning phase must be completed. After submittal of the appropriate applications and fees to BSEE and any other applicable state or local agencies, surface facilities will be cleaned and removed. All facilities, structures, and man-made items from the island will be transported to a salvage yard or approved disposal site. Pipelines will be cleaned and abandoned in-situ[1], buried a minimum of 3 feet within the seabed to deteriorate over time. Well piping will be removed to a minimum of 15 to 20 feet below the mudline. All other subsurface structures will be removed.

The onshore and island end sections of the pipeline will be removed and shipped off site for disposal or salvage. Any sheet pile that surrounds the island will be pulled completely and any concrete pad or gravel bag slope armoring will be removed to a prescribed depth below mean lower low water (MLLW). If contaminated soils are present, they will be excavated and removed from the island for offsite treatment or disposal. After grading and contouring the island surface topography to provide bird nesting habitat and marine mammal haul out areas, the island will be abandoned in-situ to erode naturally. This is the assumed procedure as abandonment in situ is the most practical option for decommissioning an offshore island and pipeline in the remote Arctic; it is cost effective and avoids unnecessary seafloor impacts with associated turbidity.

1.3. General Schedule for Decommissioning and Abandonment

Scheduling for the following activities may include potential cold shutdowns to work around seasonal limitations.

Project decommissioning will include the following sequence of activities:

- Prepare permitting documents and decommissioning plan according to regulatory and operator requirements.

[1] OCS Regulation CFR §250.1750 states " You may decommission a pipeline in place when the Regional Supervisor determines that the pipeline does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other uses of the OCS or have adverse environmental effects."

- Submit permits and fees to the BSEE Regional Supervisor for approval for the decommissioning. Submit any additional state or local permits as required. Table 1-2 (See Appendix A) includes a listing of anticipated permits that may be required for a decommissioning program.
- Shut down production first.
- Clean and flush offshore product pipeline(s) next to ensure the oil does not become immobile in the line. It will be a necessary that all product lines are cleaned and flushed immediately after shutdown. In the event that an operator shuts the facility down and walks away without attending to the lines, BSEE will have the authority to step in and ensure that all lines are adequately flushed to prevent freezing or viscous oil from being trapped in the line.
- Supply lines to the island (which could include gas, diesel, freshwater, etc.) should remain in operation and continue to support island decommissioning operations for as long as possible.
- Disconnect, plug, and abandon all production wells in a systematic fashion, ensuring that the disposal well(s) remain operational for disposal of waste fluids.
- Clean and flush all facilities piping and inject the waste into the disposal well(s) where possible.
- Clean and flush the remaining subsea pipelines and inject the waste injected into the disposal well(s).
- In the event that a disposal well is not available to receive pipeline waste streams, the waste will be shipped to an appropriate facility in Prudhoe Bay. The associated volumes and disposal costs will be negligible to the end cost model result.
- Disconnect, plug, and abandon the disposal well(s).
- Disconnect all island facilities and remove them by sealift. Note that removal of island facilities will also be dependent on the continued presence of adequate island armor, shore protection, and docking facilities
- Severe/cut well casings approximately 15 feet below the toe of the slope of the island and pull the well casings out.
- Disconnect subsea pipeline(s) at the island and onshore ends.
- Remove pipeline end sections, valves, or other fittings that could interfere with other uses of the OCS, risers, island sheet pile wall, dock structures, and armoring by sealift.
- Submit a written report to the BSEE Regional Supervisor as required, and to any state or local agencies as required.

Detailed individual timelines for each procedure are included in Appendix B

1.4. Summary of Project Facilities and Structures

1.4.1. Wells

Offshore oil and gas development wells that are drilled from a gravel island will most commonly be associated to the development of a discovered and producible field. The wells that are drilled on these instillations are typically development, injection, and disposal wells. In rare cases, an exploration well may exist on the island that may require further abandonment. These wells can have a variety of depths, up to and beyond 15,000–feet measured depth. Associated well equipment may include well houses and production control equipment inside the well houses.

1.4.2. Production Facilities

Typical crude oil production facilities on offshore islands will include well line manifolds, water and gas separation vessels, produced water and seawater treatment, metering systems, water flood pumping systems, gas-compression injection systems, electrical generation, chemical injection systems, and flaring systems to produce sales quality crude oil. Produced gas will be used by the facility for fuel gas, lift gas, and injection gas to maintain reservoir pressure. Excess gas may also be piped to shore for handling by onshore facilities. Facilities will be connected together with piping and electrical systems typically run on connecting pipe racks or subsurface in the island.

1.4.3. Pipelines

The produced oil will be piped offsite through a subsea pipeline that will transport production oil from the island to shore for further transport through a cross-country pipeline that connects to the North Slope infrastructure and the Trans Alaska Pipeline System. There may be additional subsea pipelines that transport gas, diesel, freshwater etc. to or from the island. These additional pipelines may be attached to the outside of the subsea pipeline and/or bundled within an outer casing.

1.4.4. Housing

It is generally preferable that work crews be housed on site. Existing camp facilities may be used in the early stages of the project; however, after housing modules are decommissioned and barged off site it will be necessary to provide other accommodations to house personnel for the final decommissioning tasks on site. Temporary housing may consist of an onsite work camp for sites with adequate space or a workboat may be staged at the island to provide housing. In other instances, it may be necessary to use a workboat or a helicopter to transport workers to and from onshore housing.

1.4.5. Medical Care and Facilities

Decommissioning work requires careful safety planning, and well-established safety protocols and oversight. A comprehensive safety program will be developed and implemented prior to start-up. Medical care and appropriate medical facilities should be available on site. An emergency response plan containing medevac procedures will be developed for serious injuries and illness.

1.5. General Access

It is assumed that most gravel islands, and associated pipelines and facilities, will not be located close to an onshore road system. Tundra travel and ice roads may be necessary to access onshore pipeline landing locations while island access may be achieved through floating sea-ice roads from the shore.

Summer barging will be necessary to transport equipment and materials. This will include inter-coastal local barging and larger seagoing barging for equipment and materials being transported between the island and ports outside of Alaska. Barging operations for local equipment and materials will likely be conducted from West Dock at Prudhoe Bay.

Air transportation is also typically necessary to support remote sites. Runways to accommodate small planes may be established on sea ice or on tundra, but are often less practical than using ice roads for access. While construction of an ice runway is likely to be lower cost than a sea-ice road for winter access, limitations for freight transport, weather complications, high aircraft operating costs, and other safety factors make this option somewhat impractical for a decommissioning effort. Helicopters, however, are commonly used and are necessary to support offshore gravel island operations during all phases of a decommissioning program.

1.6. Environmental and Safety Considerations for Decommissioning Activities

1.6.1. Permits and Reports

Environmental permits, if not already in place with the operator, will need to be secured from local, state, and federal agencies. Commonly required and anticipated permits and reports are presented in Table 1-2 (See Appendix A).

1.6.2. Wildlife Considerations

Marine mammals will be one of the primary environmental considerations for this project. Sound generated from transportation, heavy equipment, and use of vibratory impact hammers will be detectable underwater and/or in the air some distance away from the area of activity. The distance will depend on the nature of the sound source, the season of activity, ambient noise conditions, and the sensitivity of the receptor. At times, some of these sounds may be strong enough to cause localized avoidance or other disturbance reactions by small numbers of marine mammals. The operator will need to coordinate with the US Fish and Wildlife Service (USFWS) and the National Marine Fisheries Service (NMFS) to determine if a Letter of Authorization (LOA) for incidental marine mammal takings and/or mitigation measures may be required. It is likely that marine mammal observers will be required throughout island decommissioning.

Consideration should also be given to minimize impacts to seabirds, fish, and terrestrial wildlife. A Wildlife Interaction Plan will be developed to minimize disturbance to wildlife and to ensure worker safety related to wildlife encounters.

Polar bears are a concern both onshore and offshore. Care will be taken to minimize attracting the bears to the work site. Procedures will be established, including obtaining the required permits, for hazing polar bears as needed to ensure worker safety.

1.6.3. Subsistence Considerations

A Communications Plan and Conflict Avoidance Agreement may already be in place or may need to be negotiated with subsistence hunters and their representatives. These plans and agreements are put in place to minimize the possibility that operations, including vessels, helicopters, and other ancillary operations, may interfere with subsistence hunting; there is specific concern regarding offshore activity and disturbance that may affect the hunting of bowhead whales. Offshore activities may not be allowed in some locations during whaling subsistence season. For onshore activity, care will be taken to minimize impacts to caribou, particularly during calving and migration.

1.6.4. Pollution Considerations

Oil spills are always an environmental consideration with oil and gas operations. An approved oil spill plan will likely be available or may need to be developed and approved by BSEE, the Alaska Department of Environmental Conservation (ADEC), US Department of Transportation (USDOT), US Environmental Protection Agency (EPA), and/or US Coast Guard (USCG). Prevention measures, training, maintenance of spill response equipment, and timely response to all incidents will be a priority at all times.

A waste management plan will be developed that addresses waste storage, transportation, and disposal.

1.6.5. Safety

A comprehensive safety and training program and an emergency response program will be prepared and implemented for all decommissioning programs. Specific safety concerns will include marine operations, rig operations, crane and heavy lift operations, limited daylight, and low temperatures and storms during winter operations. Temperatures in the Arctic range from record high and low temperatures of 83 to -62 degrees Fahrenheit (28 to -52 degrees Celsius) and must be factored into worker conditions, personal safety wear and equipment performance.

A security plan will also be necessary to ensure all operations and personnel are safe from vandalism and other public threats.

2. Mobilization

2.1. Barging

Barge access to the island site is often the most effective transportation mode for the transport of equipment, materials, and facilities, especially for the transport of large modules. Inter-coastal local barge access in the Beaufort Sea is usually available from July 15 to October 1. Larger seagoing barges, which would be mobilized from worldwide resources, are typically available from early August through October 1. Sea access will be highly dependent on sea ice conditions as well as weather and wind conditions, which may move floating ice into the work area. Sea ice in the coastal Beaufort Sea is generally present from early October through July although it varies from year to year.

2.1.1. Barging Scope

Barging will be necessary for transporting materials on and off the island during the decommissioning process. This will include inter-coastal barging and larger seagoing barging for equipment and materials being transported between the island and ports outside of Alaska.

2.1.2. Barging Assumptions

The following assumptions are provided to support the cost model estimation for bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- There is a functional barge landing(s) on the gravel island.
- Local inter-coastal barging is available.

2.1.3. Barging Environmental and Safety Considerations

If large volumes of petroleum waste or product need to be barged on or off site, then absorbent boom may need to be deployed around the barge during the loading and unloading processes as a precautionary measure.

Fish, wildlife, and subsistence hunting restrictions occur on a seasonal basis. For instance, there are restrictions on marine activities during the Native Alaskan subsistence whaling season that occur from late August to late September with the end of the season being dependent on the number and success of whale strikes.

2.1.4. General Barging Procedures

Prior to the barging of equipment and materials, there must be access to barge landings on the island and on the shore, and associated staging areas will need to be established. Barge landings and ramps will be inspected and maintained before each barge arrival. Bathymetry surveys may be necessary before commencing barging operations to ensure that sufficient draft is available for landing at the island or onshore landings. If a functioning barge landing is currently not available, repairs will need to be made or a temporary beach barge landing will need to be constructed. A beach barge landing could limit available draft for barge vessels.

Equipment and materials needed for the decommissioning process will need to be staged close to the shore-side barge landing for efficient handling during decommissioning operations. Similar staging will also need to be provided on the island barge landing to accommodate offloading of modules, decommissioned materials, and waste.

Barges will be loaded from the pre-staged loads until all the desired equipment and materials have been shipped to their appropriate locations. The draft of each barge will be confirmed to ensure that the vessel can be safely accommodated at the destination barge ramp, as the draft will change with each load weight.

2.2. Tundra Travel and Ice Road Construction

Tundra travel may involve the use of all-terrain vehicles (rolligons) with weight restrictions on dry uplands, July 15 to freeze-up. Track vehicles may also be used during the winter when there is sufficient ground frost and snow cover to accommodate winter tundra travel without damage to the environment. Tundra travel for track vehicles is usually allowed to start sometime between mid- December to late January and is usually closed between late-April and mid-May. No tundra travel, except for emergencies, is allowed between winter break-up and July 15. It is recommended to maintain contact with the Alaska Department of Natural Resources (ADNR), Bureau of Land Management (BLM)) and other landowners throughout operations for travel restriction updates.

Ice roads are typically constructed in December and January and then used from early January through late March or early May. Ice roads provide greater flexibility for vehicle types, increased weight loads, and generally are more efficient than all-terrain vehicles.

2.2.1. Ice Road Scope

Ice road construction may be necessary on land or on the sea ice to access the island from the shore and to connect to the road system. The scope of this report section includes planning, constructing, maintaining, and reclamation of onshore ice roads and floating sea-ice roads.

2.2.2. Ice Road Summary of Assumptions

The following assumptions are provided to support the cost model estimation for bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- Sea-ice roads and cross-country ice roads are expected to be required to support access in most decommissioning scenarios.
- The road will be approximately 40 feet wide to accommodate 2-way traffic.
- The road will have delineators spaced every 50 feet on both sides. Placement will be staggered between the two sides of the road to effectively place a delineator every 25 feet of road.
- Ice thickness for floating sea-ice roads will be 6 feet to accommodate fully loaded tractor-trailers
- Ice thickness for cross-country roads will be a minimum of 6 – 12 inches on the tundra, the depth of ice at creek and river crossings will depend on the water depth, anticipated load weights, and the height of the banks.
- The length of floating sea-ice roads will be 10-miles or less.
- The length of onshore or grounded sea-ice roads will be 200 miles or less.
- It is not expected that a large infield-drilling rig will be transported over the floating sea-ice road.
- The water source for sea-ice roads will be seawater with a possible freshwater cap.
- The water source for cross-country ice roads will be lake water.

2.2.3. Ice Road Environmental and Safety Considerations

It is necessary to protect the underlying tundra when constructing cross-country ice roads. When constructing ice roads on the tundra, it is necessary to comply with federal, state, and local regulations for adequate frost depth and snow cover to minimize impacts. Maintenance crews must take care to operate within the road delineators to avoid disturbance or inadvertent blading of the adjacent tundra. Sedge vegetated areas, which are generally common on the Arctic Coastal Plain, are preferred for cross-country ice road routes where practicable; sedge vegetated areas are less sensitive to tundra travel and ice roads than tussock tundra areas.

Water sources for ice road construction and maintenance will generally be lakes for cross-country ice roads and seawater for sea-ice roads. When using lakes for a water source, withdrawal will be coordinated with other parties that may be utilizing the same water source. There is typically a cumulative withdrawal limit of 20 percent of the lake volume, or 10 percent of the river flow. Pumps must be fitted with appropriate screens and the intake flow must be regulated as defined in the ADF&G water withdrawal permit to ensure fish are not entrained in the pumping system.

Sea ice conditions will be continually monitored to ensure that any cracks that develop are repaired with fresh water to ensure that the sea ice is strong enough to support the desired loads.

Ice road routes may be impacted by denning polar bears during the winter season. This could result in use restrictions or the need to re-route the road around the den(s).

2.2.4. Ice Road Construction Procedures

2.2.4.1. Ice Road Construction and Maintenance Equipment

Ice road construction and maintenance requires a variety of equipment types to haul water, chip ice, clear snow and groom trails. A typical list of ice road construction and maintenance equipment is presented in Table 2-1 (See Appendix A).

2.2.4.2. Ice Road Route Planning

After mapping a preliminary route from available historical experience and satellite imagery, a formal staking survey will be conducted by a professional survey crew that accesses the route by snow machine, track vehicle or other appropriate means. It is very likely that established ice road routes are available from previous development and maintenance work for the gravel island and its onshore pipeline locations.

For cross-country ice roads, the route should minimize stream and river crossings to the extent practicable. It will also be important to consider land ownership and the potential for land use approval, access to permissible water sources, local subsistence needs, historical sensitivity, and environmental impacts. The route will be reviewed with the landowner(s); in some cases, the landowner(s) prefer the use of pre-existing routes. However, they may prefer the selection of a new route in cases where the underlying tundra has been impacted by repeated use.

For sea-ice roads, the route will avoid areas where cracking or compromised ice are known to commonly occur. Sea-ice routes will also maximize use of areas over grounded ice to minimize construction expense.

2.2.4.3. Pre-construction Preventative Measures for Ice Road Construction

A program of preventative action will be planned where the complete chain of field personnel are oriented to recognize conditions that create risk or loss of structural integrity to the ice road and how to eliminate these conditions. This chain of personnel should represent the full involvement of equipment operators, truck drivers, foremen, and superintendents to be aware and to recognize risk conditions.

Potholes and soft spots are deleterious to the structural performance of onshore ice road surfaces, while cracks and brine pockets in sea ice are also a particular safety concern for sea-ice roads. Typical causes of pothole and soft spot formation include:

- Irregular surface contours.
- Blowing snow.
- Natural cracking due to rapid temperature changes.
- Situations that result in incomplete saturation of either tundra surfaces or existing ice surfaces.

Field personnel should watch for conditions that cause potholes and soft spots during construction activities. Equipment operators and truck drivers will ensure that no air pockets have been formed and that complete saturation of snow and ice surfaces has been accomplished during construction.

Sea-ice roads will be constructed by flooding the roadbed with seawater in multiple thin layer lifts. This creates a road base that has frozen quickly with minimal opportunity for brine pockets to form leading to better structural integrity.

2.2.4.4. Pre-Construction Monitoring for Approved Ground Conditions

Pre-construction monitoring will confirm when ground conditions are appropriate to initiate onshore ice road construction.

When constructing cross-country ice roads on the tundra, it will be necessary to comply with federal, state, and local regulations for adequate frost depth and snow cover. Landowners may also have specific requirements beyond the aforementioned agencies. Typically, construction starts after ground temperatures maintain 23 degrees Fahrenheit (-5 degrees Celsius) at 1 foot below the ground surface along the route and there has been a local accumulation of more than 6-inches of snow; exceptions to snow depth are sometimes made during low snowfall years. Pre-packing activities may also be allowed earlier with special permission. Prepacking the route reduces the insulating factor of the snow cover and drives the frost into the ground at a greater rate than normal freezing. Thermistors may be set into the ground along the road route to monitor ground temperature and to allow for the earliest possible start date for ice road construction.

When constructing an ice road on the sea ice, ice augers or probes will be used to determine the natural ice thickness along the entire route. It is generally accepted that approximately 1 foot of sea ice should be present to support light vehicles for use in initiating offshore road construction. Heavier construction equipment can be used as the road thickness is built up appropriate to the vehicle weight.

2.2.4.5. Trail Grooming and Preparation

Trail groomers will be pulled behind a track vehicle to break up hard-pack snow and spread the snow evenly across the road surface. This snow layer serves as a permeable layer to absorb the water applied to the road during construction.

Prior to construction, it will be particularly important for the trail grooming crew to visually survey for potential pothole or soft spots and either to document their locations so that the route can be modified, or to ensure that construction mitigation measures are taken. During construction, equipment operators will also need to watch and report surface contour conditions that will potentially produce potholes and soft spots during the installation of the base course.

If there is sheer ice or bare tundra on the route, with no snow cover, it will be necessary to haul in snow from nearby sources. Snow can be hauled in and laid out with a loader. If no snow is available, ice chips may be gathered and used instead. A chipper can be used to cut and collect ice chips from lake ice. As with water withdrawal, no more than 20 percent of the water volume of a lake may be removed, this includes cumulative removal from other parties using the source.

When constructing sea-ice road roads, ramps will be needed to transition the roadway from the sea ice to the island or to the shore. It will be particularly important to pre-pack these ramps to produce a smooth, gradual slope. Ice chips will most likely be necessary for this portion of any sea-ice road.

2.2.4.6. Flooding the Ice Road

For onshore ice roads, water trucks will be filled at a pump house. Water sources for ice road construction and maintenance will generally be lakes for cross-country ice roads and seawater for ice roads built on the sea ice. However, when available within reasonable distance to a sea route, freshwater sources may be preferred for capping and maintaining sea-ice roads as well; freshwater creates a harder more durable ice surface with improved snow management qualities.

Water trucks will then proceed to the road site to distribute the water onto the pre-packed trail. Small water trucks will be used in the beginning until an ice bed sufficient to carry larger trucks is in place. Trucks will apply numerous controlled applications of water to build up a sufficient ice bed. Various power tools/augers will be used to drill down into the road to profile the depth of the ice bed during construction to determine construction progress. Additional applications of snow and/or ice chips may also be necessary to help build the road up to its final desired thickness.

Sea-ice roads will generally be constructed by flooding the area in leapfrog fashion with an auger or similar type water pumper. The seawater will be allowed to spread out in a uniform layer producing a roadbed that has a lenticular cross section; this prevents development of a sharp transition in ice thickness along the road edge, which in turn minimizes the potential for the ice to crack. This flooding process will be repeated along the route until the desired ice thickness or grounding is attained. A freshwater cap may be applied to the sea-ice road to provide better durability and improved snow management.

Appropriate roadbed thickness is site specific but general guidelines are:

- 1–foot for cross-country loads including heavy vehicles.
- Variable ice thickness for creek and river crossings. The final ice thickness will depend on the water depth and bank height. If extremely heavy loads are planned to cross the creeks and rivers, additional ice thickness might be.
- 6 feet for sea-ice roads used to transport equipment including fully loaded tractor-trailers.
- 8 feet for sea-ice roads used for transporting drill rigs.

2.2.4.7. Installing Delineators along the Ice Road

As the roadbed is developed, delineators will be installed along the outer edge of the road along both sides. Delineators will be spaced 50 feet apart on each side of the road, with delineators on the two sides set in a staggered fashion to each other. This effectively sets a delineator every 25 feet of road. Delineators are necessary to ensure driver safety. On cross-country roads, they also serve to help protect the tundra by indicating to grader and other maintenance operators where the edge of the ice road ends to minimize inadvertent blading of tundra.

Delineators will be set by using a chain saw to cut a vertical slot straight into the ice. The delineator will be placed in the slot and water will be applied around the delineator to freeze it into place. Vegetable oil will be used on the chainsaw to avoid potential petroleum contamination of the sea ice and/or tundra.

2.2.4.8. Berming and Capping the Ice Road

For onshore roads, a snow berm will be built along the delineated road edge that is slightly higher than the final desired roadbed thickness. Once the ice bed is thick enough to support a larger water truck, these trucks will be used to flood the bermed area with large volumes of water. The berm acts to hold the water in place minimizing run off and excess water usage. This practice also produces a smooth upper layer to the roadbed.

Construction of a sea-ice road will not require establishment of a berm during construction.

2.2.5. Ice Road Maintenance

The road will be maintained throughout the season. Graders and blowers will be used for snow removal as needed. The ice bed will be drilled or augured on a regular basis to profile its depth. Additional water will be trucked in to cap the road as needed to maintain an adequate ice bed and smooth surface.

There will be on-going vigilance to watch for and recognize conditions that could produce soft spots in the ice. Corrective actions necessary to eliminate potholes and soft spots will be taken as needed. On sea-ice roads, operators will specifically observe for cracks on the ice and sufficient ice depth to maintain safe passage. Additional fresh water will be added to any ice cracks that develop to repair the ice in those areas.

2.2.6. Ice Road Reclamation

After road use is completed, the road will be inspected during the removal of delineators and any remaining debris will be recovered for disposal. The ice road will be left to melt in place.

Cross-country ice road routes will be inspected during the following summer after all the snow and ice has melted; any debris that has emerged from under the snow will be recovered for disposal. The tundra adjacent to the road will be inspected for tundra damage; any disturbed tundra will be graded and revegetated as needed.

2.3. Helicopter Access

2.3.1. Helicopter Scope

Helicopter access is necessary to support island decommissioning activities. Helicopters may be used to transport personnel, groceries, and critical equipment parts during all phases of the decommissioning program. At a minimum, a helicopter will be available at an onshore base during times when sea ice conditions limit ice road and/or crew boat access.

2.3.2. Helicopter Assumptions

The following assumptions are provided to support the cost model estimation of bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- A helicopter-landing pad is an existing facility on the island.
- There is an operating heliport in Deadhorse to service the North Slope.

2.3.3. Helicopter Environmental and Safety Considerations

Helicopter noise can be disruptive to wildlife. There may be site-specific guidelines and/or restrictions requiring helicopters to maintain a minimum elevation while in transit over certain defined areas or areas where caribou, marine mammals, and other wildlife are observed by the pilot.

Numerous safety considerations apply to helicopter operations. Some of the primary concerns are listed below. Additional site-specific safety training will be established for all operations and closely coordinated with the aviation service provider.

- Weather requirements for minimum visibility and flight conditions will be established, carefully monitored, and communicated to the helicopter pilots.
- Helicopter weight restrictions will be established and carefully adhered to.
- Policies and procedures will be established to ensure that no gas venting is occurring during helicopter landings and take-offs.
- Policies and procedures will be established to ensure that there are no physical obstacles that pose a risk to helicopter landings and take-offs. This particularly applies to cranes with extended booms, but also applies to any equipment that may be blocking the heliport deck.
- Personnel traveling by helicopter over open water will need to wear Coast Guard approved float suits.

2.3.4. Helicopter General Procedures

It is assumed that the offshore islands will have a pre-existing helipad on site. This helipad will be inspected to ensure it is in safe working condition. In some cases, the helipad may be located on top of a flat-roofed building. If this is the case, an alternative landing site may need to be developed for the final stages of decommissioning to support activities that are ongoing after building structures have been removed.

There will also be an area adjacent to the landing site that has been cleared, designated, and marked as a cargo drop area where the helicopter can place external cargo without obstructing the landing area.

All helicopter flights will be coordinated between pilots, the person in charge of flight arrivals on the island, and the island work crew. Coordinated scheduling will help ensure that gas venting, crane operations, or other activities that could endanger helicopter operations, are not occurring during landings and take offs. When practical, well-coordinated scheduling can minimize interruptions to shift work as well as ensure safe landing conditions.

Sling loading or use of cargo nets are common practices for transporting large or bulky cargo on or off site. Helicopter companies will have established procedures for carrying and unloading external cargo, which will be reviewed by island personnel and closely followed.

3. Well Plugging and Abandonment

Assumptions about well abandonment were based on oil and gas expertise and data gathered from a review of existing and typical exploration, development, and disposal wells in the Beaufort Sea. These wells are listed in Table 1-1. (See Appendix A)

3.1. Well Plugging and Abandonment Scoping

Well plugging and abandonment includes all procedures from rig–up, circulating and killing the well, verifying casing integrity, testing and maintaining the well control equipment, pulling the tubing string, running the work string, and cementing the production, intermediate and surface intervals in the wells.

3.2. Well Plugging and Abandonment Assumptions

The following assumptions are provided to support the cost model estimation of bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- Rig maintenance downtime is assumed to be 5 percent or 30 minutes a day for routine maintenance and minor repairs during operations and 1-day a month for major repairs, which is a standard allotment in rig contracts.
- Unforeseen maintenance downtime due to rig failures is typically 5 to 10 percent of productive time. The cost model has an input cell to enter this number. However, the initial base assumption in the model is 7 percent, as this is a reasonably conservative number. This value is highly variable dependent upon the time of year the operations are taking place and the condition of the equipment selected to perform the work.
- There will also be weather events that occur that will prevent operations from taking place on site. This number varies seasonally. During the summer months, the nonproductive time is less than 5 percent; in the winter, this number can be as high as 25 percent. The model uses the downtime schedule listed in Table 3-3. (See Appendix A)
- The well will have a tubing string that allows full circulation of the well for displacing the well with kill weight fluid.
- The integrity of the casing is assumed to pass all required tests.
- There is no anchoring plug holding the tubing.
- The tubing hanger will accommodate either a two-way check valve or a backpressure valve.
- The sealing elements in the tubing hangar are competent and providing a positive seal.
- All cement plugs will require a competent bottom barrier for the cement plug to rest on, either the base of the well or a Cast-Iron Bridge Plug.
- Average normalized running speed is 17 feet per minute.
- Normalized running speed includes connections and make up time.
- The pulling speed of the work string out of the cement plug is 10 feet per minute.
- The annulus between the production casing and intermediate casing has not been covered with cement at the shoe of the intermediate casing.

3.3. Well Plugging and Abandonment Environmental and Safety Considerations

Workover and drilling rig operations present risks to the health and safety of the rig crews and well site service personnel. Risks will include being struck by equipment or falling materials, burns from cutting and welding activities, tripping, falling from heights, electrical shock, and chemical hazards. Project specific safety, environmental training, and certification of rig and service personnel will help ensure that onsite personnel understand their job duties as well as the safety and environmental protocols that go with each position.

While the hydrocarbon production zones in a well may be depleted, there will still be the possibility that gas is present in the production casing or outer annuli. Control of the well will be maintained at all times and any remaining hydrocarbon zones will be isolated by cementing operations.

Proper and routine maintenance of the rig and service equipment will also be essential to minimize risks associated with mechanical failures.

3.3.1. Rig Intake and Acceptance Procedure

3.3.1.1. Rig-up Procedure

3.3.1.1.1. *Off Site Rig-up*

The rig may need to be prepared for workover operations off site to verify that all rig components and ancillary equipment come together and function properly. This offsite rig-up will function to mitigate many unforeseen failures and complications that might otherwise occur at the well site. Rig issues will be repaired or mitigated before the rig is transported to site. The rig will need to be disassembled again for transport to site.

3.3.1.1.2. *On Site Rig-up*

After the rig has been fully mobilized to the well site, it will be rigged up on site over the first well in the abandonment program. Following completion of the rig-up process, system functionalities will be verified and the rig will go through a formal acceptance procedure to determine it is fit for duty.

3.3.1.1.3. *Mobilizing between Well sites*

The rig that will be selected to perform this work will preferably have pad drilling/workover capability and be able to move rapidly from one well site to the next without requiring a full rig-down. This will improve the overall onsite operational efficiency of the project and should minimize the footprint of the equipment.

3.3.1.2. Rig Maintenance Procedures

3.3.1.2.1. *Routine Maintenance*

As with all mechanical equipment, the rig will be required to go through routine maintenance. The rig contractor should have a detailed maintenance program in place. The plan should allow for approximately 30 minutes a day of general maintenance and minor repairs during operations, as well as one-day a month for major repairs. This maintenance program will be reviewed prior to awarding a contract and final rig acceptance.

3.3.1.2.2. *Unforeseen Maintenance*

Mechanical systems associated with drilling/work over rigs often have significant unplanned mechanical failures. Unforeseen mechanical failures at the well site may require operations to shut down. Adequate spares will need to be maintained on site or on the shore to enable timely repair of unforeseen mechanical failures.

3.4. Well Plugging and Abandonment Procedure

3.4.1. Killing the Well

A well kill is usually the first step in the well abandonment process. Once the well is dead, then the blowout preventer (BOP) and the associated equipment (BOPe) will be installed and following the abandonment steps will be conducted.

3.4.1.1. Determining Kill Weight Fluid

Kill weight fluid will be determined by measuring the maximum surface pressure and assuming that the pressure is coming from the shallowest exposed formation to ensure the most conservative mud weight is used (assuming the pressure is coming from a deeper portion of the formation could result in an insufficient mud weight to completely kill the well).

The surface pressure and the formation interval in true vertical depth will be used to determine the equivalent pressure fluid gradient in pounds per gallon (ppg). This fluid gradient will be used to determine the fluid weight necessary to provide adequate hydrostatic pressure to kill the well. Each well may have a different fluid weight required to counter balance its formation pressure. In the event that this initial calculation is too low, the density of the fluid in the well may need to be increased or be replaced with a different fluid to achieve the necessary hydrostatic pressure.

The kill weight fluid will be comprised of a clear workover fluid with non-freezing properties to allow the fluid to sit stagnant in the wellbore for an indefinite amount of time without freezing. This fluid will also have to be designed to mitigate the risk of corrosion to the tubulars that are in the well.

A clear fluid is recommended over a solids-laden fluid for this application to mitigate the risk of creating obstructions in the well. If a solids-laden fluid is used, it may lose its carrying capacity as it sits stagnant and fine particulates such as barite sag will precipitate over time. These particulates have the potential to settle into the well seal profiles or mechanical profiles of downhole jewelry, which could lead to complications in the removal or functioning of downhole equipment.

3.4.1.2. Mixing the Kill Weight Fluid

Many workover fluids have complicated chemistries that require precise mixing practices to achieve appropriate fluid properties. This includes consideration of the significant hazards associated with mixing these complicated salts to the desired fluid weight. A list of the various kill weight fluid salt types and their related density and typical crystallization temperature (TCT) is provided in Table 3-1. (See Appendix A)

3.4.1.3. Displacing the Well with a Kill Weight Fluid

Displacing the well will be performed by pumping fluid down the tubing string and up the annulus at a rate that is sufficient to remove all produced fluids from the wellbore. This typically requires a pump rate of 3 to 5-barrels per minute (bpm). After the well has been fully displaced with the kill weight fluid, two additional well volumes will be pumped to ensure there is no gas entrained in the well fluid. At this point, the well will be shut in. The pressure on both the tubing and casing will be monitored to verify that there is no pressure building in the well. This will indicate if the weight of the fluid used was sufficient to overbalance the pressure in the well and kill the well.

If there is no tubing string or production string in the well to allow full circulation of the well, then the well will either need to have kill weight fluid “Lubricated and Bled” or “Bullheaded” into the well to kill the well. The Lubricate and Bleed method is gentler on the well system than the Bullhead method. Depending upon the well conditions, lubricating may also be the prudent course of action to minimize stress on the wellbore. The drawback to the Lubricate and Bleed method is that it takes longer to effectively kill the well than Bullheading. However, Bullheading exerts higher pressures along the wellbore. The condition of the wellbore and surface equipment will determine which method is best suited to kill the well.

3.4.1.4. Monitoring Shut-in Pressure

After kill weight fluid has been circulated around the well, the wellbore will be shut in and the pressure monitored for a minimum of 30 minutes. If pressure is measurable at the surface, this pressure should be bled off and the pressure re-monitored at the surface. If the pressure builds to the same value or higher, then the weight of the kill weight fluid was insufficient and a new density must be calculated. The well will then need to be circulated with the new kill weight fluid.

3.4.1.5. Well Kill Flow Checks

After it has been verified that no pressure is measurable at the surface, then the well will be opened up to atmospheric pressure to allow for a visual flow check. The well will be opened to atmospheric pressure for 30 minutes and any returns will be collected in a small volume tank to allow observation of small volume gains.

If after 30 minutes there has been no flow out of the wellbore, the procedure will proceed to the next step of abandoning the well.

If the well flows during the flow check, the well will be shut in and monitored for pressure. The pressure in the well will continue to be monitored until the pressure to surface has stabilized. After the well is shut in, the pressures will be monitored at the surface for a minimum of 1 hour. If a pressure is measurable at the surface, then the well will be circulated with a fluid of sufficient weight to over balance the pressure coming from the formation. If there is no observable pressure gain in the well, an extended duration flow check will be performed to determine the cause of the flow from the wellbore.

3.4.2. Well Control Equipment

3.4.2.1. Configurations

The BOPe will be designed, tested, and maintained in a manner to ensure well control under the foreseeable conditions of the well. A kick tolerance calculation will be performed for all possible hole configurations and gas migration possibilities before selecting the BOPe. BOP configuration requirements will follow current regulations.

3.4.2.2. Rigging Down the Production Tree

To be able to rig-up the BOP, the production tree on the well will need to be rigged down. Prior to rigging down the production tree, the well must be fully isolated from downhole pressure. Either a backpressure valve or a two-way check valve will be set inside the profile of the tubing hanger.

If the profile is not available inside the tubing hanger, it will be necessary to set a tubing plug inside the tubing string. The tubing plug will be placed at a depth sufficient to handle the maximum differential pressure across the plug; this will prevent it from being ejected out of the wellbore. Creating this pressure barrier is crucial to ensuring the safety of the personnel rigging down the production tree.

3.4.2.3. Rigging up the BOPe

The BOPe will be rigged up on the well to provide pressure containment. The configuration of the BOPe will be determined based on the maximum anticipated surface pressure in the well.

3.4.2.4. BOPe Pressure Testing

3.4.2.4.1. *BOPe Pressure Testing Regulations*

All well control equipment will be tested to the same maximum allowable surface pressure (MASP) as approved in the Application for Permit to Drill (APD) or Application for Permit to Modify (APM). An incompressible medium with non-freezing properties will be used such as the same clear fluid that was used to kill the well. Testing will follow the specific requirements listed below:

3.4.2.4.2. *Pressure Test Frequency*

- BOP systems must be tested at the time of installation.
- BOP systems must be tested at least every 7 days (except blind or blind-shear rams).
- Blind or Blind Shear Ram systems must be tested at an interval of every 30 days
- BSEE must be notified 72 hours in advance.
- All pressure tests should be conducted by all crews that operate the equipment.
- If repairs require disconnection of a pressure seal in the assembly, then the affected seal must be pressure tested.

3.4.2.4.3. *Pressure Test Procedures*

- Test pressure must hold for a minimum of 5 minutes after the pressure has stabilized.
- Testing will include a low-pressure test of 250-psi followed by a high-pressure test for each component in the well control system.
- Testing is conducted in the direction that the equipment is intended to hold pressure.
- High-pressure tests must be conducted at the MASP of the BOP equipment.
- Annular-type BOPs must be tested at the minimum of the MASP or 70 percent of the rated working pressure.
- Variable bore pipe rams must be tested against the largest and smallest sized tubulars in use in the well (jointed pipe, seamless pipe).

3.4.2.5. Well Control Drills

All personnel engaged in well abandonment operations will participate in a weekly BOP drill and safety training to familiarize the crew with appropriate safety measures. Well control drills must also be conducted every 7 days during operations. Specifics about the required well control drills are available in API Standard 53.

3.4.2.6. Test Records

BOP test pressures will be recorded on pressure charts or with a digital recorder.

The time, date, and results will be listed in the operations log for all pressure tests, actuations, inspections, and crew drills of the BOPe system and system components. Any problems or irregularities observed during the BOPe testing must also be listed in the log along with any repairs or remedies. BOPe test documentation must indicate the sequential order of the BOPe testing, and the pressure and duration of each test. If there is a BOP test plan retained on site that contains the required information listed above, it is allowable to reference that plan instead of listing the details in the log. (30 CFR 250.450)

3.4.2.7. BOPe Maintenance

Periodic maintenance inspections are required for all well control operations.

3.4.2.7.1. *Maintenance Inspection Frequency*

BOPe must be inspected every third day.

3.4.2.7.2. *Maintenance Inspection Procedures*

The BOP system must be inspected according to API Recommended practices for Blowout Equipment Systems for Drilling Wells (API Standard 53 (4^{th} Edition, November 2012)) to ensure that all equipment functions properly.

3.4.2.7.3. *Maintenance Inspection Records*

Inspections must be documented to show how the inspection met or exceeded API Standard 53 (4^{th} Edition, November 2012), what procedures were used, and all inspection results and observations.

Records must be kept on file on the rig for 2-years and available to BSEE upon request.

3.4.2.7.4. *Routine Maintenance Procedures*

BOPe must be maintained to ensure that the equipment functions properly and safely. Maintenance must follow the provisions listed in API Standard 53 (4^{th} Edition, November 2012).

3.4.2.7.5. *Routine Maintenance Records*

- Maintenance procedures must be documented to show how the requirements listed in API Standard 53 (4^{th} Edition, November 2012).
- Records must be kept on file on the rig for at least 2-years. BSEE may request records to be kept on file for a longer time at their discretion.

3.4.3. Pulling the Tubing String

3.4.3.1. Pulling the Backpressure Valve

After verifying that the BOPe is functioning appropriately, the tubing, backpressure valve and tubing hanger will be pulled from the well. To pull the backpressure from the well, it will be re-verified that there is no trapped pressure under the hanger by recording the pressure in the annulus and bumping the check valve. The manufacturer's procedure for pulling the backpressure valve will be followed.

3.4.3.2. Pulling the Tubing Hangar

The tubing hanger will be pulled with the running tool; the manufacturer's procedures for running the tool and pulling the hanger will be followed. The tubing hanger will then be pulled from the well and the tubing set in the rotary table of the rig. The tubing head will be removed from the tubing and set aside.

If an As-Run program or well schematic is available, it will be noted whether a production packer was installed as a part of the production string of tubing. If the packer is retrievable, as in the case of a straight pull to release feature, the shear-release will be additive to the total tubing weight. The pounds of force required to shear-release the tool will be noted in the program and the condition of the pipe will be considered when determining the maximum amount of pull available to release the packer. If the packer cannot be released with the pipe, a wireline unit will be required to make a cut in the tubing string. Tubing can then be pulled out of the well.

3.4.3.3. Pull the Tubing from the Well

The tubing will be pulled from the well and laid down for recycle or disposal. The pulling speed of the tubing will be determined by the maximum drop in pressure in the hydrostatic column available before the formation fluids begin migrating into the wellbore. This pulling speed will be controlled by the rheology of the fluid and the annular clearances between the tubing in the casing. The surface fluid tanks (pits) should be monitored to confirm that this is not happening. If swabbing is occurring, pull speed will be reduced accordingly.

Also, in cases where a production packer is affixed to the tubing string, pull speed will be reduced due to the packing element’s tendency to swab the well while pulling.

3.4.4. Setting Wireline Retrievable Bridge Plug (WLRBP)

3.4.4.1. Rigging up the Wireline

A wireline unit and appropriate lubricator will be rigged up on top of the BOP to allow setting a full gauge WLRBP inside the existing casing above any open formations. The procedure of the service company who owns the wireline unit will be followed for rig-up. Appropriate safety measures need to be taken while rigging up the WLRBP as many of them are set with explosive charges.

3.4.4.2. Running the WLRBP

The WLRBP assembly will be made up and loaded into the lubricator. The assembly will then be lowered into the well monitoring casing collars to verify the plug setting depth.

3.4.4.3. Setting WLRBP

The manufacturer’s setting procedure for the WLRBP will be followed to set the plug and verify its proper setting.

3.4.5. Casing Integrity Testing

It is crucial to conduct a casing integrity test or mechanical integrity test of the well to verify that there are no leaks or failures in the casing string prior to abandoning the wellbore. These tests are critical for verifying that the casing and the wellbore meet the defined assumptions of the abandonment criteria. For the test to be acceptable, the pressure must meet the following requirements:

- The casing will be tested to 70 percent of its burst rating or 100 percent of the maximum anticipated surface pressure, whichever is lower.
- The casing pressure test must be held for at least 30 minutes without a pressure drop of more than 10 percent.
- The casing pressure test must be carried out for a minimum 30-minute monitoring period with no disturbances. An acceptable test is defined as stable if decreasing pressure fall off is less than 5-psi/minute for the final 15 minutes.
- Pressure chart recordings must be fully legible, clearly labeled with the well name, well serial number, casing size, test start time and stop time, and date and signature.

3.4.6. Retrieving Wireline Retrievable Bridge Plug

3.4.6.1. Rigging up Wireline

A wireline unit and appropriate lubricator will be rigged up on top of the BOP to allow a full gauge WLRBP to be retrieved from the casing. The procedure of the service company who owns the wireline unit will be followed for rig-up.

3.4.6.2. Unsetting the WLRBP

The manufacturer's release procedure for the WLRBP will be followed. The pressure across the WLRBP will be equalized before the tool is fully released and pulled. This will prevent the plug from being pushed up the wellbore.

3.4.6.3. Pulling the WLRBP

The WLRBP will be pulled off the bottom of the well slowly to minimize the risk of drawing and swabbing wellbore fluids into the well and will continue to be pulled slowly for the first 200 feet.

3.4.7. Running the Work String

3.4.7.1. Selection

The work string design will be specific to the operation taking place. A general work string design will include 200 feet of tail pipe on the bottom of the drill string that was rented with the rig. If a cast-iron bridge plug is necessary, the work string configuration will require a running tool on the bottom. The tubing tailpipe will minimize disturbance and damage to the cement plug that could occur when the plug is pulled out.

This decision to set a cast-iron bridge plug below all cement plugs, except for the first one, is not required by regulation. However, this will improve operational efficiency and provide better downhole barriers for the final wellbore abandonment.

3.4.7.2. Wear Bushing

Prior to running any work strings in the well, a wear bushing will be set inside the tubing hanger profile. The wear bushing is designed to protect the tubing hanger profile from damage during well operations. Because this well is being abandoned, this profile is not critical for well life. However, preserving this profile during well work will allow for additional rig-ups in the event that the well cannot be successfully abandoned in the time duration of the operation being performed. It also ensures that BOP tests can be conducted successfully as the test plug is often set in the tubing hanger profile.

3.4.7.3. Running Speed

The running speed of the work string with the tailpipe will be determined based on actual wellbore parameters and conditions in the field. This maximum speed will be designed to account for operational efficiency and to prevent detrimental damage to the operation.

3.4.8. Circulating the Well

3.4.8.1. Condition the Fluids

After the work string has reached the required depth, the kill weight fluid will be circulated in the well; this will verify that the fluid column in the annulus remained consistent and uniform throughout the pipe tripping operations. The properties of the fluid going into the well should equal the properties of fluid coming out of the well. During well circulation, the maximum achievable pump rate should be pumped, and if possible, the work string should be reciprocated and rotated to aid in cleaning the wellbore. A minimum annular velocity of 120 feet per second (fps) should be achieved to ensure the fluid in the annulus is in turbulent flow and will provide sufficient cleaning capabilities.

3.4.8.2. Flow Check

After the well has been circulated, uniform fluid will be measured in the annulus and inside the work string. The pumps will be shut down in the well and monitored for 30 minutes to verify that the well is static.

3.4.9. Cementing Requirements

3.4.9.1. Rigging up

The cementing unit will be rigged up and tested prior to conducting cementing operations.

3.4.9.2. Cement Slurry

The cement slurry will be designed to provide an optimal thickening time so the cement will not set up while being pumped. However, the thickening time should also be short enough that when the cementing operation has finished the cement will set rapidly; this is important to mitigate potential gas influx and migration into the well while the cement hydrates. The cement also needs to provide adequate compressive strength to be able to resist flow after it has been fully set. Where the cement slurry is to be set across a permafrost zone, it will be designed to have a low heat of hydration and to cure before it starts to freeze.

3.4.9.3. Compatibility Testing

Adequate compatibility testing will be performed between the fluids used to circulate the well and the fluids to be used during the cement job. This is important as some brine can have a detrimental impact on the quality of cement jobs. The mix water will be tested before mixing the slurry.

3.4.9.4. Lead Cement Spacer

The lead cement spacer will be designed to clean the casing and promote a strong bond between a cement plug and the casing. The spacer will also be designed to minimize potential contamination effects from any of the fluids in the well. The volume of the spacer should account for 150 feet of length inside the work string by casing annulus.

3.4.9.5. Tail Cement Spacer

The tail cement spacer will be designed similar to the lead cement spacer and should account for the same volume by height as the lead cement spacer. The purpose of this spacer is to prevent contamination of the cement from the displacement fluid and ensure the wellbore is balanced on top of the cement plugs.

3.4.9.6. Cement Volumes Validation

Two independent calculations of cement volumes will be made and verified prior to pumping cement. The onsite supervisor will complete cement volume calculations based on hole depth and casing size and confirm the cement volumes required for the job.

3.4.9.7. Pumping Cement Job

3.4.9.7.1. *Mixing Cement*

The cement manufacturer's procedure for mixing and pumping the cement for the specific slurry blend will be used. During the mixing process, a cement sample will be taken of the dry product, and the mix water, as well as the mixed slurry. These samples will be stored for further analysis should they be required later. A density measurement on all samples will be conducted using a manual density scale to verify that the digital sensors on the cementing unit are reading the appropriate value.

If using a batch mixer, the full volume of cement should be mixed and verified prior to pumping the cement job. If a continuous blending cement mixer is used, multiple samples will need to be taken of the cement slurry to verify that the entire slurry is uniform.

3.4.9.7.2. *Pumping Cement*

Before pumping cement slurry down the well, a foam ball will be loaded into the work string to separate the wellbore fluids and lead spacer from the cement and to minimize contamination of the cement slurry. Another foam ball will also be loaded at the end of the cement slurry and before the tail spacer and displacement to protect the cement slurry from contamination.

All the volumes for mixing the cement will be closely measured to verify the proper amount of cement has been pumped into the well.

3.4.9.7.3. *Displacing the Cement*

After the entire cement slurry has been mixed and pumped into the well, a displacement volume will need to be pumped. The displacement volume will equal the volume necessary to balance a cement plug in the well so that the top of the cement inside the work string is the same as the top of the cement in the annulus. The volume of displacement will be carefully measured via the displacement tanks on a cement unit, and the total volume of displacement should not exceed the calculated value. Throughout the entire pumping of the cement job, the following values will be recorded: volume, pressure, and rate for both the work string and casing side.

3.4.9.8. Pulling Work String Out of Cement Job

After the cement slurry has been successfully placed in the wellbore, the work string will be slowly pulled out of the cement slurry. The work string will be pulled carefully to prevent contaminating or disturbing the cement plug that has been pumped. The pulling speed of the work string out of the cement plug will depend upon the consistency of the cement slurry that was pumped in the well. The work string will be pulled an additional 10 feet above the calculated top of cement. This will allow the work string to clear the cement column.

3.4.9.9. Cleaning Out Work String

After the work string has been fully pulled from the cement column in the well and properly spaced out, the cement remaining inside the work string will be reversed out. Reversing the cement slurry out of the well will minimize the pump time required and decrease the risk of accumulating cement inside the annulus of the well. Two work string volumes will be pumped down the annulus and up the work strings to verify that the inside of the work string and the surrounding annulus is clean of cement.

3.4.9.10. Testing the Cement Plug

After the cement plug has enough time to set and reaches the necessary mechanical strength for pressure testing, the cement plug will be pressure tested to 1,000 psi. The results will be plotted against the mechanical integrity test performed before the cement job was pumped. The pressure must hold and not drop more than 10 percent in 15 minutes.

3.4.10. Cementing the Production Interval Well

3.4.10.1. Running in the Well

The work string will be run into the well to 5 feet above the bottom of the well and circulation established while preparing to pump the cement job.

3.4.10.2. Determining the Volume of Cement

The necessary volume of cement plug will be determined based on the height requirement necessary to provide adequate zonal isolation and wellbore integrity. This value will be calculated with and without the work string in the well. A cement plug will be set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.

However, there are multiple different methods of setting a cement plug. This method was chosen because it will provide the most conservative estimate of the volume of materials required for isolating the well. Other approved volumes can be found in the abandonment regulations. (30 CFR 250.1715)

3.4.11. Cementing the Intermediate Interval Well

3.4.11.1. Running in the Well

The work string will be run into the well to 200 feet below the mud line and circulation will be established before setting the cast iron bridge plug.

3.4.11.2. Setting Cast-iron Bridge Plugs

The procedure for setting the cast-iron bridge plug will vary based on its manufacturer and the manufacturer’s procedures will be followed. After the cast-iron bridge plug has been set, the setting tool will be unlatched from the bridge plug and the work string pulled up 5 feet above the bridge plug.

A cast-iron bridge plug has been chosen as the ideal method for providing a competent base for the cement to be set on. However, alternative options include setting a cement retainer, a viscous pill, or a swellable packer.

3.4.11.3. Determining the Volume of Cement

The volume of cement necessary to set the plug will be determined based on the height requirement necessary to provide adequate zonal isolation and wellbore integrity. This value will be calculated with and without the work string in the well. This plug should extend 200 feet above the top of the bridge plug.

3.4.12. Cementing the Intermediate Interval of an Exploration Well

It is assumed that the annulus between the production casing and intermediate casing in an exploration well has not been filled with cement at the shoe of the intermediate casing. Cement will need to be placed in that annular area to create a lateral barrier in the well; this will prevent cross flow between zones.

3.4.12.1. Perforating Production Casing

A wireline perforating run will put holes in the production casing to allow access to the annulus; this will allow a cement to cover the cemented interval of the intermediate casing. Wireline perforating guns will be rigged up on the well and run 100 feet below the base of the intermediate casing set point; 12 shots per foot and 360° phasing will be fired. This will provide an optimal flow path for the cement to circulate up to allow that interval to be cemented.

3.4.12.2. Running in the well with work string

The work string will be run into the well to 150 feet below the base of the intermediate casing and circulation established before setting the cast iron bridge plug.

3.4.12.3. Setting cast-iron bridge plugs

The setting procedure for cast-iron bridge plugs will vary based on the manufacturer and the manufacturer's procedures will be followed. After the cast-iron bridge plug has been set, the setting tool will be unlatched from the bridge plug and the work string pulled up 5 feet above the bridge plug.

A cast-iron bridge plug has been chosen as the ideal method for providing a competent base for the cement to be set on. Alternative options are to set a cement retainer, a viscous pill, or a swellable packer.

3.4.12.4. Establishing annular circulation

After the cast-iron bridge plug is been set, circulation will be established between the production casing annulus and the inside of the production casing. This will be done by opening the production casing annulus valves, shutting the BOP pipe rams, and pumping down the work string. Once good circulation is established in the annulus, and two bottoms up have been pumped, a cement squeeze job will be pumped inside the production casing annulus.

3.4.12.5. Determining volume of cement for production casing annulus

The volume of cement necessary to set the plug will be determined based on the height requirement necessary to provide adequate zonal isolation and wellbore integrity. This value will be calculated with and without the work string in the well. A cement plug at least 200 feet long will be set in the annular space.

3.4.12.6. Testing the annular cement plug

The cement plug in the annulus will be pressure tested before the plug can be set inside the tubing; this will verify that the annular plug has not been compromised.

3.4.12.7. Determining volume of cement for production casing plug

The volume of cement necessary to set the plug will be determined based on the height requirement necessary to provide adequate zonal isolation and wellbore integrity. This value will be calculated with and without the work string in the well. A cement plug at least 200 feet long will be set in the production casing.

3.4.13. CEMENTING THE SURFACE INTERVAL WELL

3.4.13.1. Running in the well

The work string will be run into the well to 200 feet below the mud line and circulation will be established before setting the cast iron bridge plug.

3.4.13.2. Setting cast-iron bridge plugs

The setting procedure for cast-iron bridge plug will vary based on its manufacturer and the manufacturer's procedures will be followed. After the cast-iron bridge plug has been set, the setting tool will be unlatched from the bridge plug and the work string pulled up 5 feet above the bridge plug.

A cast-iron bridge plug has been chosen as the ideal method for providing a competent base for the cement to be set on. However, alternative options include setting a cement retainer, a viscous pill, or a swellable packer.

3.4.13.3. Determining volume of cement

The volume of cement necessary to set the plug will be determined based on the height requirement necessary to provide adequate zonal isolation and wellbore integrity. This value will be calculated with and without the work string in the well. A surface cement plug must be a minimum of 150 feet long, with the top of the plug no more than 150 feet below the mud line.

3.4.14. CUTTING THE SURFACE CASING

An internal rotary cutting tool will be used to cut the casing from the innermost string all the way to the outermost string at a depth of 20 feet below the mud line. There are many tools available on the markets that are capable of doing this; the manufacturer's procedure will be followed for the selected tool. If possible, the surface casing strings will be pulled with the rig to reduce the impact on later operations.

Alternatively, the casing strings and conductors may be cut by explosive techniques and pulled with a crane and vibratory hammer. This same equipment spread will be employed to pull sheet pile on the island during the later decommissioning stages.

4. SUBSEA PIPELINE(S) DECOMMISSIONING ABANDONMENT AND DISPOSAL

4.1. SUBSEA PIPELINE(S) SCOPE

Decommissioning an offshore hydrocarbon flow line requires careful operations. Purging and cleaning involves the handling, collection, storage, and disposal of class I and class II oilfield wastes. Detachment of the pipeline requires consideration of the need and means to stabilize or anchor any stored energy strain that may cause the line to shift or buckle.

The scope of this report section extends from the island terminus of the pipeline, across the seafloor, to a shore-crossing terminus (assumed to be approximately 200 to 300 feet inland from the high tideline) where the pipeline will ascend up to surface grade and meet a shut off-valve. The ascent to surface grade may be through a vertical riser structure or it may be an excavated gradual "sweep". At the shore-crossing terminus, the offshore pipeline will connect to an onshore cross-country pipeline that leads to a tank farm, pump station or a shared-carrier line. The cleaning and removal of the cross-country pipeline, and any associated facilities (e.g. shore module with valve – shut-offs etc.) are outside the scope of this report.

Additional support pipelines for fuel and/or freshwater and infrastructure such as electrical supply may be attached to the outside of the pipeline or bundled with the pipeline in an outer casing. These additional lines are also included within the scope of this report section.

4.2. Subsea Pipeline(s) Abandonment Summary of Assumptions

The following assumptions are provided to support the cost model estimation of bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- The pipeline will be in good condition with no substantial damage, buckling, corrosion or leakage. This is considered a reasonable worst-case assumption because of the high standards that are applied to offshore pipeline construction materials and pipeline inspection and maintenance protocols.
- The pipeline will be operating up until the date of decommissioning, or it will be maintained in an interim status that prevents freeze-up of internal product or fluids. Allowing the subsea pipeline to freeze would result in extensive complications with no established means of resolution. Thus, it is assumed that the government would either require the operator to schedule decommissioning to occur immediately subsequent to final operations, or require the company to maintain the pipeline in an interim status that would prevent freeze-up. In the case of bankruptcy, or default, it is assumed that the government would step in to ensure the pipeline was decommissioned in a timely manner to prevent freeze-up.
- There are additional support pipelines attached to the outside of the subsea pipeline and/or bundled within an outer casing.
- Associated pipeline facilities such as pumps, valves, pig launchers and receivers, tank farms, etc. will be in place and operational to support operations.
- All mobile equipment, tools and materials for excavation, cleaning, and removal will need to be transported to site.
- Cleaning and flushing operations may be conducted in either flow direction.
- Six pigging runs will be required to clean the oil pipe to an acceptable level.
- Three pig runs will be required to clean a diesel line.
- Water and gas lines will not require pigging.
- At least one ‘slug’ using two pigs to move a batch of solvent down the oil line will be used.
- The final pipeline flushing and filling of the pipeline(s) will use seawater.
- Pipeline waste will be stored in tanks with suitable containment near the shore-crossing terminus.
- The pipeline will need to be anchored prior to cutting and disconnecting the line to avoid potential pipeline movement that may result as tension strain in the line is released.
- Injection wells will be available off site on the North Slope, for the disposal of pipeline waste streams.
- Waxes and sludge removed from the waste streams will not be suitable for injection into a disposal well and will need to be shipped out-of-state to an approved disposal facility.
- Salvage materials will need to be transported off site to the lower 48 for disposal.

- Decommissioning is generally more difficult and costly during the winter months. As a worst-case scenario, the procedures provided in this report section will assume decommissioning, cleaning, and cutting the pipeline are all initiated during the winter months.
- The closest year-round gravel road system is 5 - 30 or more miles away.
- An ice road connecting to an existing road system will be built to provide access to the island and shore-terminus site and for transportation of waste off site. Ice roads are typically used between January through April.
- The pipeline will be constructed using current industry technology with no trapped annuli where hydrocarbon can build up.

4.3. Subsea Pipeline Environmental and Safety Concerns

Some of the materials involved in the purging and cleaning of the pipeline may be hazardous in nature and will be handled with care for human safety and environmental protection. Hydrocarbons, and oftentimes the chemicals used to clean the pipelines, have the potential to be flammable, explosive, corrosive, toxic and/or erosive.

Personnel will be qualified and trained to work with these materials. Safety data sheets will be readily available. There will be established working protocols that include clear assignment of roles, responsibilities, and lines of authority.

It is likely that environmental compliance and spill control plans applicable to federal, state, and local regulations will be in place from previous operations. These plans may need to be modified to accommodate the decommissioning activities or it may be necessary to fully develop new plans before any work begins that identifies and minimizes risks to the environment, as well as providing contingency response measures.

4.4. Subsea Pipeline Decommissioning Procedures

4.4.1. Access

During the summer months, shore-crossing sites may be accessed by low bearing-surface pressure vehicles that utilize large inflated tires such as rolligons. These vehicles, when operated with limited loads, can provide cross-country travel without damaging the tundra.

These same vehicles, along with track vehicles or other all-terrain vehicles, can provide winter access once there is sufficient surface frost and snow cover. Winter access for a greater variety of vehicles can be accommodated by constructing ice roads; this is a common practice in the Alaskan Arctic.

Vehicle travel on the ocean ice can also be conducted using rolligons and track vehicles carrying limited weight-bearing loads, but travel availability may be limited by ice conditions, particularly at the beginning and end of the season. An ice road may be built on the ocean to better accommodate travel out to the island.

4.4.2. Equipment

Mobilization for pipeline decommissioning will likely involve a variety of equipment. Some facilities may have some of this equipment still on site, and some additional equipment will need to be brought in specifically for the decommissioning activities. A full list of equipment is provided in Table 4-1. (See Appendix A)

4.5. Pipeline Abandonment[2]

4.5.1. Shut Down Procedures

4.5.1.1. Oil Pipeline(s)

Oil pipeline(s) will be shut down as soon as the facility ceases to produce oil; the oil pipeline(s) will be taken out of service, oil inflow shut off, and all double valves or block and bleed lines opened. **Cleaning and flushing the line(s) must be conducted immediately following shutdown**. This is necessary, and supported by requirements within federal offshore oil leases, to ensure that contents are not allowed to freeze in a pipeline.

4.5.1.2. Support Pipeline(s)

It will be preferable to maintain use of the support pipeline(s) throughout the well abandonment and facility decommissioning processes. These lines will also need to be cleaned and flushed immediately after they are shutdown to ensure that the contents are not allowed to freeze in the line.

4.5.2. Pipeline Inspection

Pipeline(s) will be tested for integrity, leakage, ability to withstand pressure and potential obstructions prior to initiation of any purging, cleaning or disconnection. It is assumed within this report that all pipelines will be intact based on the high performance standards applied to subsea pipeline construction and maintenance in the Alaskan Arctic. If pipelines are not in satisfactory condition for proceeding with the decommissioning process listed below, then the operator will need to employ measures outside the scope of this report to ensure the decommissioning is conducted in a safe and environmentally sound manner.

An inspection pig will be used to determine pipeline integrity; it will also gather data on the type, location, and quantity of residue that needs to be removed. These data will be used to develop a comprehensive cleaning plan for the project that is effective, safe, and environmentally responsible. Residues can range from simple liquids or gases to sludge, waxes, and hard scale; they may be acidic, neutral, toxic or flammable. The cleaning plan will address the appropriate types of pigs, propellants, solvents, number of pig runs, pressure of pig runs, and other options to effectively clean the pipeline. For instance, light oily residue may be cleaned with methanol, but heavy waxes and scales may require an acid wash followed by neutralization and a final wash to dilute the cleaning chemicals before abandonment of the line. Where there is a lot of residue, it may be preferable to run several cleaning pigs with low efficiency instead of one highly efficient cleaning pig as this could reduce the risk of displacing too much residue and causing a blockage in the line.

4.5.3. Cleaning Process for Oil and Diesel Pipelines

Cleaning the pipeline will be accomplished using a variety of cleaning and separation pigs, forced through the pipeline by a suitable propellant.

[2] Pipeline Decommissioning Regulations are found in CFR §250.1750 - 1754

While the scope of this report only applies to the offshore portion of the pipeline, it is reasonable to assume that pigging the entire offshore and cross-country line together would be advisable to ensure product does not freeze in either of the lines and that all lines are abandoned in an environmentally responsible manner.

4.5.3.1. Flow Direction

Most Alaskan Arctic subsea pipelines are designed for bi-directional flow allowing the most flexibility in pigging and flushing options. It is assumed for this report that all subsea pipelines will be bi-directional.

In the unexpected case of a lines designed for unidirectional flow, the product pipeline will flow from the island towards the shore, however, other associated pipelines such as a diesel or gas lines may flow from the shore to the island. The fittings and the equipment associated with the pipeline(s) are set up to accommodate the original direction of flow and may cause complications if trying to reverse the flow direction. In most cases, it is advisable that cleaning and purging of unidirectional pipelines follow the same directions as the original operational flow.

4.5.3.2. Water Withdrawal

It is presumed within this report that the oil facility operator will have current, applicable seawater withdrawal permit(s) and functioning pumping facilities, suitable for use with seawater, available as needed during the cleaning process. Where applicable permits do not already exist, they will be obtained from the appropriate regulatory agency(s). Filtering will be employed as required.

4.5.3.3. Pigs

It is assumed for this report section that pig launchers and receivers will already be present on the line. If they are not presently available, they will need to be temporarily installed.

The flow line diameter for the pipeline(s) is expected to range from 4 to 24 inches. Analysis of associated smaller lines may be required to determine if pigging is feasible. If pigging is not suitable, these smaller lines will be purged and cleaned by a full flow process using suitable liquids and/or foam balls in place of pigs.

Pigs may be run in trains, or a series of trains. The number of pigs and the length of the train will be limited by the amount of pressure that can be safely applied to drive the train and the residue it has picked up. This pressure must not exceed the maximum allowable working pressure of the pipeline as determined from the inspection pig data. Typically, one to six pig runs may be necessary to clean the oil pipeline and one to three pig runs will likely be necessary to clean a diesel pipeline.

4.5.3.4. Flushing Agents, Solvents and Propellants

Pigs may be used with seawater or other specialized solvents to dissolve and flush residue out of the system.

Slugs may be used to batch a liquid between two pigs to augment cleaning the line. The slug may be seawater or it may contain other solvents as needed. Slugging allows the line to be cleaned with less solvent than would be used filling the entire line to flush it. The slug liquids would be collected at the pig receiving-site and stored in tanks for disposal.

Propellants may vary depending on the pig and the content in the pipeline. Seawater is readily abundant at offshore islands and is generally used instead of alternative propellants. Compressed air or nitrogen, foam or gels may also be used as a propellant if necessary. Use of foam or gels should be preceded by a slug to avoid the possibility of forming an explosive mixture of oxygen and hydrocarbons inside the pipeline.

4.5.3.5. Special Circumstances

Pipelines may become deformed after several years of use due to various physical oceanographic forces such as ice scour, strudel scour, and upheaval or buckling of the ocean floor. Cleaning pigs may not be effective at cleaning hydrocarbons out of some misshapen areas of the pipeline. To ensure there are no pockets of residual hydrocarbons left behind, sending a slug of suitable liquid media trapped between two foam balls can be effectively applied.

4.5.3.6. Determining the Effectiveness of the Cleaning Process

The effectiveness of the cleaning process will be determined by collecting samples of the waste stream for chemical and physical analysis. Sample results for hydrocarbon and waste material content in the solvents that were injected into the line will be compared with results for solvents collected at the end of the line.

4.5.3.7. Leaving Residue within the Pipeline

In general, all pipeline residues will be removed. However, in some cases where residue quantity is low and difficult to remove, the residue may be left in place if it meets with approval of the appropriate agencies. Similarly, residual cleaning solvents will be removed unless they will be diluted in the final filling of the pipeline to meet applicable water quality standards. Final residue levels left in the line prior to final abandonment will be specified in the decommissioning plan and permit approvals.

4.5.3.8. Final Flushing of the Line

When chemical analyses of the slug liquid indicate that the contents in the pipeline meet marine water quality standards, the appropriate agencies will be contacted for official confirmation that the line is suitable for abandonment. A final flush of the line will be conducted using seawater. Seawater is both suitable and readily available for use at offshore islands. Because the pipeline is being abandoned to disintegrate over time, it will not be necessary to reduce the corrosivity of the seawater with any oxygen scavengers or biocides as are often used for lines being salvaged or set aside for future use. Filling the pipe with seawater will also help to ensure the pipe maintains negative buoyancy when abandoned in the seabed.

4.5.4. Collection, Storage and Disposal of Pipeline Waste Streams

All pipeline cleaning media and debris will be collected and stored per the applicable environmental regulations. A Waste Management Plan will be developed prior to operations to ensure that appropriate storage vessels, adequate storage capacity, secondary containment, appropriate testing protocols/equipment for characterizing wastes, suitable means of transportation, proper manifesting and record keeping protocols, and approved disposal sites have been established that will meet the anticipated project waste streams.

4.5.4.1. Onsite Disposal of Pipeline Waste Streams

In some instances, it may be possible to inject wastes within the onsite permitted injection disposal well(s) if they are still in use for injecting waste and have not been plugged and abandoned.

4.5.4.2. Onsite Storage of Pipeline Waste Streams with Transport to North Slope Disposal Wells

Wastes can be stored in tanks for transport to offsite permitted disposal wells on the North Slope. Vacuum trucks or pumps can transfer waste from storage tanks as needed for transportation to the approved waste disposal sites. Tank storage will be designed to ensure adequate waste storage capacity and to protect the waste stream from freezing by using insulation, heating, or additives that lower the freezing point of the liquid. Waste storage should include secondary containment with sufficient capacity to hold 110 percent of the largest vessel within the containment area. Prior to transport, wastes will be tested to ensure they meet receiving criteria at the destination disposal site.

Wastes collected on the island end can be transported to shore using all-terrain vehicles for limited weight loads during the wintertime. Construction of an ice road on the ocean may allow transport of larger loads. Alternatively, local barges could transports wastes from the island to the shore.

Wastes collected and stored on the shore, or brought to shore from the island will then be transported by tundra travel or ice road across the tundra, as necessary, to connect with a gravel road and delivery to a North Slope disposal well.

Some facilities will include a cross-country pipeline that intersects and/or terminates along a road system. Access for the collection and transportation of pipeline waste streams may be accommodated by launching the pigs and solvents at the offshore island and sending the wastes down the offshore pipeline and on up through the cross-country pipeline. Waste could then be collected where the cross-country pipeline intersects or terminates along the road system. Receiving the pig and pipeline wastes at a roadside location allows the advantage of year-round accessibility, avoidance of ice-road construction and avoidance of tundra travel. These factors should result in lower costs and lower risk to the environment.

4.5.4.3. Onsite Storage of Pipeline Waste Streams with Transport Out-of-State

Some waste streams that contain sludge and waxes may need to be containerized and shipped out of state to an approved waste facility. These may require transport to the road system to be trucked south. For some wastes, it will be necessary to wait until late summer when ocean ice breaks up enough to allow ocean-going barges to transport waste streams to an out-of-state disposal facility.

4.6. Considerations for Cleaning Other Associated Pipelines

4.6.1. Gas Pipelines

Residual gas will be vented or flared once the pressure in the gas pipeline has been reduced to the extent possible using operating facilities or a pull down compressor. Pigging will be conducted with an inert substance to prevent explosive mixtures. Seawater, which is readily abundant at an offshore

Arctic island, will be used instead of nitrogen or other inert gases due to its availability. Seawater will also provide weight to ensure negative buoyancy during abandonment.

4.7. Disconnecting the Pipeline(s)

4.7.1. Timing

After the pipeline(s) has been cleaned and flushed, it will be in suitable condition to be left in place until a convenient time to fully disconnect and abandon the line.

It will be most efficient to remove all project pipelines at the same time. This may also be necessary for safety purposes, as it could be dangerous to torch-cut an abandoned oil pipeline if it is lying adjacent to an operating gas pipeline. Disconnecting the oil pipeline(s) will therefore be coordinated with the disconnection of the supply lines; this will occur after they are no longer needed for the decommissioning of the wells and island facilities.

4.7.2. Pipeline Strain

Pipeline "strain" data will be collected to understand where and how much tension is present in the pipeline. The pipeline would have originally been laid on solid substrate that provided equal support down the line. However, over time the heat from the oil would likely have created a thaw-bulb in areas where the substrate was initially frozen around the pipeline. This, along with other oceanographic forces could result in substrate settlement and movement. As a result, the pipeline may not be well supported and may essentially be suspended along some or all of the line. Cutting a line that is under a lot of strain may cause the pipe to shift substantially creating a potentially dangerous situation. Data from the inspection pig will be used to determine how to best engineer an anchor system to prevent problems during decommissioning. If an anchor-system is required, the load calculations will include consideration for an order of magnitude level safety factor.

Using prepared load calculations, an anchor cable/winch-type system will be designed that will allow for using a cable to connect the pipeline to heavy equipment, fixed pile, or another suitable anchor. The anchor will need to be able to withstand the calculated loads of strain energy that may be released once the line is detached from the island and/or shore facilities. The anchoring system will be installed in place during the excavation and prior to cutting operations. Anchor patterns will be developed as needed and included in the pipeline removal permit if required by the BSEE Regional Supervisor.

4.7.3. Pipeline Detachment

4.7.3.1. Removal of the Shore-Side Riser Structure and Shore-Crossing Pipeline Section

The shore-crossing pipeline section remains buried for approximately 200 to 300 feet inland from the high tideline (to protect it from erosion) where the pipeline ascends up to surface grade. The ascent to surface grade will likely be through a vertical riser structure or it may be an excavated gradual "sweep". At surface, the shore-crossing pipeline section will be connected to a cross-country pipeline that leads to a tank farm, pump station or a shared-carrier line.

This shore-crossing pipeline will be disconnected from the cross-country pipeline. Any pipeline sections that are shallower than 3 feet below ground surface will be removed. The BSEE Regional Supervisor may also require placement of concrete mats at the pipeline ends at their discretion.

The riser will also be cut 3 feet below ground surface and removed.[3] The area around the shore-crossing pipeline and riser will be excavated to create a work area to accommodate cutting and removal of the upper pipeline and riser.

Prior to excavation, plans will be developed to protect any archaeological and/or sensitive biological features during the removal operations; conduct any associated surveys to determine marine mammal presence or other species of special interest. The BSEE Regional Supervisor must be notified at least 48-hours before removal operations are initiated.

Excavation will be conducted with shore-based excavation equipment. Cutting the pipeline and the riser will generally be conducted with a cutting torch or pipe cutting tool. All production risers will be flushed with seawater before removal. A crane or backhoe will be used to remove the riser and the shore-crossing pipeline sections. The excavated material will be backfilled and graded as appropriate.

The pipeline section and riser will be stored with other solid wastes on site for transport and disposal or salvage.

4.7.3.2. Removal of the Island Riser Structure and Island-Crossing Pipeline Section

The pipeline approach to the island, much like the shore-crossing pipeline section, may be through a vertical riser structure or more likely, it will be a buried gradual “sweep”. At surface, the island pipeline terminus will be connected to the production facilities.

This island terminus pipeline will be disconnected from the production facilities. Any pipeline that is less than 3 feet below the seabed surface will be removed. If there is a riser, it will be cut off 3 feet below seabed surface as well. The area around the pipeline will be excavated to create a work area to accommodate cutting and removal of the upper pipeline, upper riser section if present, and any other support apparatus.

Prior to excavation, plans will be developed to protect any archaeological and/or sensitive biological features during the removal operations; conduct any associated surveys to determine marine mammal presence or other species of special interest. The Regional Supervisor must be notified at least 48 hours before removal operations are initiated.

Excavation will be conducted with barge-based or island-based excavation equipment. Cutting the pipeline and the upper section of the riser will generally be conducted with a cutting torch or pipe-cutting tool. All production risers will be flushed with seawater before your removal. A crane or backhoe will be used to remove the upper pipeline and riser for placement on the island for temporary storage or directly onto a transport barge. The excavated material will be backfilled and graded as appropriate.

The pipeline section and riser will be stored with other solid wastes on site for transport and disposal or salvage.

[3] See CFR regulation §250.1751 (f)

4.7.4. Offshore Pipeline In-situ Abandonment

The offshore pipeline(s) will remain buried in-place in the seabed to naturally deteriorate over time. Prior to abandonment, the pipeline(s) will have been thoroughly purged and cleaned to ensure there will not be any release of hydrocarbons or other hazardous materials into the marine environment as the pipeline deteriorates.

The pipeline will be filled with seawater, cut at both ends, capped and the pipeline ends reburied in the seabed. Negative buoyancy, a product of pipeline structural weight and the weight of the pipeline contents (seawater), will help the pipeline remain settled in the seabed. As the pipe degrades, the contents will naturally equilibrate with the surrounding seawater and negative buoyancy will be maintained.

4.7.5. Cross-Country Pipeline Abandonment or Disposal

The cross-country pipeline will need to be cleaned, removed and salvaged for future use, or removed and disposed of at an appropriate facility. Further details for cross-country pipeline decommissioning are outside the scope of this report.

5. Removal of Island Structures and Facilities

5.1. Island Structures and Facilities Scope

Island structures and facilities include oil production modules, housing facilities, and other support buildings. All buildings are assumed to be modular and either built on piling or concrete foundations. Associated infrastructure includes fuel piping, freshwater piping, electrical wiring, etc. Process and support modules may range in size from large modules that weigh between 200 to 5000-tons, and are generally transported by sealift, to smaller modules that typically weigh less than 120-tons, and are generally transported by truck.

All structures and facilities will be cleaned, disconnected, and removed from the island as part of the decommissioning of the offshore plant. Island structures and facilities will include:

- Process and support modules and buildings.
- Pipe racks.
- Storage tanks.
- Flare towers.
- Communication towers.
- Wellhead houses and all associated surface and subsurface piping.
- Structural, electrical, and instrumentation infrastructure.

5.2. Island Structures and Facilities Assumptions

The following assumptions are provided to support the cost model estimation for bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- The gravel island will be designed as a production island.
- All non-manmade materials are allowed to be abandoned in place; the gravel will be left in situ.
- All possible waste streams will be disposed of locally.

- Facility operator will have water withdrawal permits.
- The facility will have not produced naturally occurring radioactive material (NORM).
- Structures will be modules that can be disassembled into sections for removal.
- The facility will be abandoned in a reasonable time after last production.
- The facility will be functional throughout the abandonment of the site.

5.3. Island Structures and Facilities Seasonal Aspects

Demolition work can occur in winter or summer conditions. Transporting larger modules off site, however, must be done in late summer when ocean-going barge access is available.

5.4. Island Structures and Facilities Access

Access to the island includes local barge service in the summer, ocean-going barge service in late summer, and ice transport during the winter. Rolligons and all-terrain vehicles may be used on the ice for weight-limited loads when conditions allow. An ice road can also be built on the ice during the winter season depending on sea ice conditions.

5.5. Island Structures and Facilities Environmental and Safety Concerns

Some of the materials involved in the purging and cleaning of the facility pipelines, tanks, and process vessels may be hazardous in nature and should be handled with care for human safety and environmental protection. Hydrocarbons, and oftentimes the chemicals used to clean the pipelines, have the potential to be flammable, explosive, corrosive, toxic and/or erosive. Personnel will be qualified and trained to work with these materials. Safety data sheets will be readily available. There will be established working protocols that include clear assignment of roles, responsibilities, and lines of authority.

It is likely that environmental compliance and spill control plans applicable to federal, state, and local regulations will be in place from previous operations. These plans may need to be modified to accommodate the decommissioning activities or it may be necessary to fully develop new plans before any work begins that identifies and minimizes risks to the environment, as well as providing contingency response measures.

Safety personnel will inspect the various process systems prior to disconnecting and demobilizing modules to ensure that there is no longer a hazardous explosive condition on the island.

5.6. Equipment

A variety of equipment is required to removing island structures and facilities. A full list of anticipated equipment is provided in Table 5-1. (See Appendix A)

5.7. Island Structures and Facilities Removal

5.7.1. Sequencing Decommissioning of the Island Modules

Disconnection of the modules will be sequenced so that the interior lighting and ventilation systems are available and useable to the dismantling crews until the last possible moment before loading onto transporters.

The need for continued use of the housing facilities and a timely transition to a portable camp or workboat will also be considered when sequencing the decommissioning of the modules.

5.7.2. Cleaning the Island Facilities

Prior to shutdown of the facilities, all fluids will be removed from piping systems, process vessels, and storage tanks. All piping systems will be cleaned of any residual decontaminants and fluids by pumping appropriate solvents and water flushes through the lines.

Where an onsite disposal well is operational, fluids will be injected down disposal wells in accordance with the well permits. When an onsite disposal well is not available for use, fluids will be pumped into appropriate tanks, stored at a location with adequate secondary containment, and transported off site to an appropriate disposal facility. This may require tundra travel to connect with the road system to truck the tanks to another North Slope disposal well, or transporting by truck to out-of-state waste facilities. Local barges can also be used to transport wastes to North Slope disposal wells. Ocean-going barges can also be used to transport wastes out-of-state, if necessary.

5.7.3. Disconnecting and Separating Island Modules

After the piping systems have been cleaned and approved for complying with appropriate standards, work will begin on separating the modules and other infrastructure in preparation to demobilize the structures. Scaffolding or man-lifts will be required at many of these separation points.

Piping systems will be disconnected from the individual modules and other infrastructure pieces on the island. Plastic pipe covers will be placed on open pipe ends within and protruding from the modules to minimize water intrusion during decommissioning and transport. Flanged spools will either be unbolted and removed or flame cut to separate the modules.

Instrumentation cables and tubing and electrical distribution cables will be cut to separate the modules and process infrastructure. A strict lockout tag-out system will be maintained to ensure there is no electrical power in the cables being cut.

5.7.4. Preparing the Island Modules to be Moved

Crews will remove all piping, cable tray, architectural and structural components underneath each module that could interfere with access to the support points needed to lift the module and move it onto the transport barge. Additionally, shipping braces may have to be added to the modules to ensure against structural failure while being transported on the barge. Module openings and penetrations will be reviewed and adapted with temporary closures as needed to keep water from entering the modules during shipment.

5.7.5. Preparing Other Ancillary Structures to be Moved off the Island

As work proceeds on the process modules, crews will also begin removing ancillary structures and facilities on the island. These will include pipe racks, flare towers, storage tanks, wellhead houses, offices, trailers, camp, warehouses, etc. Stairways and ladders from the modules to grade will be removed as the work inside the modules is completed. Crews will utilize the large lift cranes, lowboys and loaders to lift, transport and stage these materials on barges for transport.

5.7.6. Moving Island Modules by Barge

The larger modules will be lifted using either a complicated multi-crane lift or a heavy duty “Scheuerle” type self-propelled transporter that lift large modules off of their support piles or foundations using hydraulic platforms. These transporters can be configured to the individual needs of each module. In the correct configuration, they have the ability to lift and move modules as large as 6000-tons. These transporters also have the ability to confirm the current weight of each module to confirm the barge-loading plan.

Careful sequencing and placement of each module on the appropriate barge will be accomplished to ensure the barges will be stable and that they will draft the expected water depth. Loading of large modules onto barges will likely be conducted with the barge grounded on the sea bottom. After loading, the barge will be de-ballasted and pulled from the loading dock. Transporters will be shipped underneath the last module loaded.

5.7.7. Removing Pilings and Foundations

After the modules, ancillary equipment, and remaining materials have been removed from the island, crews will remove the support pilings and concrete foundations. Steel pipe piling will be extracted using a large crane and a vibratory extractor. If the ground is still frozen, it may be necessary to drill next to the pilings and inject hot water or steam to break down the ad freeze bond between the pile and soil at depth. Concrete foundations will be excavated and loaded out on barges or tractor-trailers.

5.8. Wastes

Large modules will be directly loaded onto ocean-going barges and transported out of state to a salvage yard or disposal site. Ocean-going barges are available in August and September depending on ice conditions. Smaller modules may also be directly loaded onto ocean going barges if there is adequate space available, and if the timing is appropriate.

Truckable size modules, most of the ancillary materials, and process piping have the option of being hauled off the island on an ice road to Prudhoe Bay in late winter. However, the most cost efficient option may be to load truckable modules and material on sealift barges along with the larger modules for transported out of state to disposal and salvage facilities.

Concrete foundations will be disposed of at an approved landfill on the North Slope, used as shore protection rubble, or transported out-of-state.

6. Removal of Obstructions, Stabilization Structures and Armoring

6.1. Scope for the Removal of Obstructions, Stabilization Structures and Armoring

The removal of the island obstructions will be done late in the project after all the island facilities have been removed. These items will include the following:

- Sheet piling walls that surround the island's top sides and form the barge unloading docks,
- Concrete mat slope protection or gravel bags (armor) that surrounds the island,
- Filter fabric underneath the concrete mats or gravel bags,
- Bolsters and anchors used to tie-off barges and equipment, and
- Subsurface lines and utilities.

The final disconnection of the subsea pipeline and removal of the pipeline end sections and risers will likely occur within this same timeframe with possible efficiencies to be gained by coordinating these activities.

6.2. Assumptions for Removal of Obstructions, Stabilization Structures and Armoring

The following assumptions are provided to support the cost model estimation of bonding requirements. In order to ensure adequate bond coverage, the assumptions are based on a reasonable worst-case scenario.

- Summer temperatures will have penetrated into the active layer of the island to enable excavation of subsurface lines, some sheet pile, and armoring material(s).
- Summer barge service will be available.

6.3. Seasonal Aspects for the Removal of Obstructions, Stabilization Structures and Armoring

Activities associated with decommissioning the island armor and structures require careful coordination with the seasons. These activities must both be initiated and concluded within a seasonal window between summer thaw and winter freeze-up. It is important that armor removal operations are completed prior to the onset of fall and winter storms. With the removal of shore protection, the island will become increasingly susceptible to storm damage. Inclement weather during this phase of the decommissioning will be dangerous and could result in significant project setbacks. Summer ocean access is also necessary so that barges can access the island for transporting excavation equipment and cranes and for the removal of modules, equipment, and waste materials. Winter freeze-up will also close off necessary barge access.

6.4. Access for the Removal of Obstructions, Stabilization Structures and Armoring

Equipment and materials will primarily be transported to the site by barge for this work. Prior to initiating activities, it may be desirable to arrange for early transport of these materials and equipment to the island across the ice while the ocean is still frozen; this would allow an early start on performing the work. Limited weight loads could be transported by rolligon or all-terrain vehicles if ice conditions are suitable, but larger loads will require the construction of an ice road from the shore to the island.

6.5. Environmental and Safety Concerns for the Removal of Obstructions and Stabilization Structures and Armoring

Safety concerns will include overhead handling of large modules and concrete pads, uneven ground surfaces with excavated areas, and exposure to inclement weather in addition to general heavy construction safety concerns.

Removal of island armoring may disrupt marine life; concrete mats may be functioning as an artificial reef. Discussions will be held with the appropriate environmental agencies to determine if it is environmentally preferable to leave the concrete mats in place, conduct a partial removal to a certain depth, and/or dispose of the concrete mats on the seafloor in an approved location, or other options that may arise during discussion with the agencies.

It is expected that the island will naturally erode eventually stabilizing as a subsurface mound of gravel and sediment that may migrate laterally over time. Discussions will be held with the appropriate environmental agencies to determine if site reclamation requirements will be required to provide wildlife habitat during the interim period until the island stabilizes under the water. Reclamation requirements may consider grading to allow haul-out or denning sites for marine mammals, and/or leaving a hummocky surface that accommodates bird nests. As these are gravel islands without any topsoil or organic matter, it is not expected that there will be any requirements for planting vegetation.

Demobilization and island abandonment activities are expected to have the potential to disturb or displace small numbers of marine mammals. In particular, the use of the vibratory hammers to remove sheet piles may produce noise at levels that is harmful to marine mammals. Some activities may require Letters of Authorization from USFWS and/or NMFS for incidental takings of marine mammals depending on the presence of marine mammals in the area. There may be some periods, such as during the bowhead whale migration, when the use of a vibratory impact hammer or other equipment will not be allowed.

6.6. Equipment

Heavy equipment and cranes will be necessary to remove sheet piles, concrete mats and other armoring from the site. A full list of anticipated equipment for the island decommissioning work is provided in Table 6-1. (See Appendix A)

6.7. Removal of Obstructions

The sheet piles that surround the island providing shore protection will be pulled using one of the cranes and a vibratory hammer/extractor. The cranes will be land-based working from the island surface. If summer thaw has been insufficient and sheet piles are still frozen in their foundations, it may be necessary to drill down next to the structure and inject steam to thaw and release the pilings prior to extraction. The sheet pile wall will be pulled from the majority of the island periphery, with the exception of the boat ramp/dock area, which will be temporarily left in place to accommodate offloading equipment onto barges.

Concrete mats surround the base of the island to protect or armor the island from erosional forces. These will be lifted out by crane or an excavator to the island surface for transport and disposal unless otherwise allowed by the environmental agencies. Gravel bags may also have been used as armor, or they may have been used to repair or improve slope protection. Gravel bags will be pulled and set down on the island surface; the bags will then be slit open to allow the gravel to spill out on the island. Backhoes with extended reach arms or draglines will scrape the island slopes to remove the filter cloth, discarded bags, and any broken pieces of concrete mats. Divers may be employed to ensure that all of the filter cloth and any bag debris will be collected and removed from the island.

The island will be inspected for signs of petroleum-impacted soils. Any contaminated areas will be appropriately excavated and the contaminated material packaged for transport and disposal in accordance with regulatory requirements. The site gravel will be tested to obtain agency approval for abandonment.

The sheet piling at the ramp and dock face will then be removed. The dock site will be graded to allow the remaining equipment to be offloaded on to roll-on/roll-off barges for transport.

6.8. Waste Storage, Transport, Disposal

- Sheet piles will be stacked and loaded onto barges to be transported to Deadhorse, Seattle, or other out-of-state locations.
- Concrete mats will be loaded onto local barges for disposal in a local landfill at Deadhorse or at other North Slope locations.
- Gravel bags and filter fabric will be packaged up, loaded onto local barges, and transported to Deadhorse or other North Slope locations for disposal in the local landfill.

6.9. Clearance [4]

Within 60 days after permanently plugging a well, platform or removing facilities, the site must be verified as clear of obstructions. Verification will be accomplished through annual side scan sonar or multi-beam bathymetry surveys to track the in situ abandonment. Divers may also inspect and photograph the site, or a remote operated underwater vehicle may be used to videotape the site.

7. Site Reclamation

A bulldozer will grade the island to a rough and hummocky profile conducive to bird nesting and marine mammal haul-outs or denning. A final inspection will be made to ensure that all man-made materials have been removed from the island. Once the grading and final cleanup has been accepted by the appropriate agency(s), the bulldozers will then be loaded out onto local barges and returned to Deadhorse and the crew demobilized.

8. Project Completion

Once the re-grading has been done and accepted, equipment demobilized, and scrap sent out-of state or to the local landfill, the entire decommissioning project will be completed.

[4] See BSEE regulations CFR §250.1740 - §250.1743

APPENDIX A: TABLES

Table 1-1. Alaska OCS wells reviewed to determine well types and depths for the region.

FIELD	WELL NAME	OPERATOR	WELL CLASS	API NUMBER
EXPLORATORY	OCS Y-1663 WARTHOG 1	ARCO	Exploratory	55-171-00012-00-00
EXPLORATORY	OCS Y-1650 LIBERTY 1	BP	Exploratory	55-201-00009-00-00
EXPLORATORY	OCS Y-0191 BEECHY PT 2	EXXON	Exploratory	55-201-00002-00-00
EXPLORATORY	OCS Y-0195 TERN 1	SHELL	Exploratory	55-201-00003-00-00
EXPLORATORY	OCS Y-0196 TERN 2	SHELL	Exploratory	55-201-00004-00-00
EXPLORATORY	OCS Y-0197 TERN 3	SHELL	Exploratory	55-201-00004-01-00
BADAMI	BADAMI UNIT B1-38	SAVANT	Exploratory	50-029-23407-00-00
ENDICOTT	DUCK IS UNIT MPI 2-30B	HILCORP	Development	50-029-22228-02-00
ENDICOTT	DUCK IS UNIT SDI 4-04A	HILCORP	Development	50-029-21968-01-00
ENDICOTT	DUCK IS UNIT MPI 2-02	HILCORP	Disposal	50-029-21568-00-00
NIKAITCHUQ	NIKAITCHUQ SD37-DSP1	ENI	Disposal	50-629-23451-00-00
NORTHSTAR	NORTHSTAR UNIT NS-34	BP	Development	50-029-23301-00-00
NORTHSTAR	NORTHSTAR UNIT NS-33	BP	Development	50-029-23325-00-00
NORTHSTAR	NORTHSTAR UNIT NS-34A	HILCORP	Development	50-029-23301-01-00
NORTHSTAR	NORTHSTAR UNIT NS-33A	HILCORP	Development	50-029-23325-01-00
NORTHSTAR	OCS Y-0181 SEAL 2 FED 1	SHELL	Exploratory	55-029-21074-00-00
NORTHSTAR	OCS Y-0180 SEAL 4 ST 1	SHELL	Exploratory	55-029-21236-00-00
NORTHSTAR	NORTHSTAR UNIT NS-32	HILCORP	Disposal	50-029-23179-00-00
OOOGURUK	OOOGURUK NUQ ODSN-02	CAELUS	Development	50-703-20671-00-00
OOOGURUK	OOOGURUK ODSN-43	CAELUS	Development	50-703-20692-00-00
OOOGURUK	OOOGURUK KUP ODSN-42B	CAELUS	Development	50-703-20605-02-00
OOOGURUK	OOOGURUK KUP ODSK-35	PIONEER	Development	50-703-20560-00-00
OOOGURUK	OOOGURUK UNIT ODSDW 01-44	CAELUS	Disposal	50-703-20556-00-00
OOOGURUK	OOOGURUK NUQ ODSN-26	CAELUS	Injection	50-703-20642-00-00
OOOGURUK	OOOGURUK TOR ODST-46	CAELUS	Injection	50-703-20631-00-00
OOOGURUK	OOOGURUK NUQ ODSN-27	CAELUS	Injection	50-703-20655-00-00
OOOGURUK	OOOGURUK ODSN-19	CAELUS	Injection	50-703-20685-00-00
PRUDHOE BAY	PRUDHOE BAY UN PTM P2-51A	BP	Development	50-029-22262-01-00
PRUDHOE BAY	PRUDHOE BAY UN PTM P2-51AL1	BP	Development	50-029-22262-60-00
PRUDHOE BAY	PRUDHOE BAY UNIT D-18B	BP	Development	50-029-20694-02-00
PRUDHOE BAY	PRUDHOE BAY UN PTM P2-15A	BP	Injection	50-029-22409-01-00

Table 1- 2. Permitting and reporting requirements for decommissioning activities.

APPLICATIONS AND REPORTS	SUBMISSION	REGULATION
BSEE Decommissioning Regulations [76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012]		
(a) Initial platform removal application.	In the Alaska OCS Region, submit application to the Regional Supervisor at least 2-years before production is projected to cease	§250.172
(b) Final removal application for a platform or other facility	Not more than 2 years after the submittal of an initial platform removal application to the Alaska OCS Region	§250.1727
(c) Post-removal report for a platform or other facility	Within 30 days after you remove a platform or other facility	§250.1729
(d) Pipeline decommissioning application	Before you decommission a pipeline	§250.1751(a) or §250.1752(a), as applicable
(e) Post-pipeline decommissioning report	Within 30 days after you decommission a pipeline	§250.1753
(f) Site clearance report for a platform or other facility	Within 30 days after completing site clearance verification activities	§250.1743(b)
(g) Form BSEE0124, Application for Permit to Modify (APM) The submission of your APM must be accompanied by payment of the service fee listed in §250.125	(1) Before you temporarily abandon or permanently plug a well or zone	(i) §§250.1712 and 250.1721 (ii) When using a BOP for abandonment operations include information required under §250.170
	(2) Within 30 days after plugging a well	§250.1717
	(3) Before you install a subsea protective device	§250.1722(a)
	(4) Within 30 days after you complete a protective device trawl test	§250.1722(d)
	(5) Before you remove any casing stub or mud line suspension equipment and any subsea protective device	§250.1723
	(6) Within 30 days after you complete site clearance verification activities	§250.1743(a)
Possible Federal Permits Commonly Required (May not be all inclusive)		
FAA – Temporary Air Strip Authorization	Submit at least 30 days prior to construction.	Form 7480-1
USFWS – Letter of Authorization for Marine Mammal/ Polar Bear Take	Submit at least one year prior to initiating related activities.	50 CFR 18.27(f)
EPA Spill Prevention Control and Countermeasures Plan (SPCC).	The Plan must be certified by a licensed professional engineer prior to storing oil on site.	40 CFR 112 Applies to: Facilities with an aggregate aboveground oil storage capacity greater than 1,320 gallons or underground storage capacity greater than 42,000
USACE 404 Nationwide 14 Linear Transport Projects - Permit for Wetland Fill along road or pipeline route	All 1 – 2 months	Clean Water Act – Section 404

Possible State Permits Commonly Required (May not be all inclusive) (continued)		
ADEC Temporary Storage of Drilling Waste	Submit a minimum of 30 days prior to the storage of drilling waste.	18 AAC 60.430
ADEC Air Quality Minor General Permit (Drill Emissions)	Allow 2 – 4 weeks	18 AAC 50.542 and 18 AAC 50.544
ADEC Oil Discharge Prevention and Contingency Plan (ODPCP)	Allow at least 6 months	AS 46.04.900
ADNR Section 106 National historic Preservation Act - Cultural Clearance for Excavation	Allow at least 30 days prior to land	36 CFR 800 AS 41.35 and 11 AC 16.030
ADNR Temporary Water Use Permit for Ice Road Construction	Allow 2 – 4 weeks	11AAC93.220 Required to withdraw more than 500 gallons of water per day from any one source
ADNR Land Use Permit – for onshore work on State lands, including ice roads	Allow 4-6 weeks	AS 38.05.850 Required prior to some activities on state land
ADOA Permit to Drill	Required prior to drilling Allow 2 weeks	20AAC 25.005
ADOA Annular Injection	Allow 2 weeks	20AAC 25.080
ADF&G Public Safety and Wildlife Interaction Plan for Hazing and Wildlife Interaction	Allow 4-6 weeks	5AAC 92.033
ADF&G Title 16 Fish Habitat - Water Withdrawal	Required prior to using the water resource Allow 2-4 weeks for processing	AS 16.05.841
Local Regulations		
North Slope Borough Administrative Approvals and/or Development Permits for activities on borough lands	Submit with payment at least one month prior to operations	Title 19 of the North Slope Municipal Code Form 100
Archaeological Review Request	Submit with payment at least one month prior to operations	Title 19 of the North Slope Municipal Code Form 600
Archaeological Clearance	Submit with payment at least one month prior to operations	Title 19 of the North Slope Municipal Code Form 500
Good Neighbor Plan	Not subject to formal approval	No formal regulations
Notification of activities to local communities as applicable for each project	Varies with individual agreements	Varies with individual agreements
Site closure inspections as applicable for each project	Varies with individual agreements	Varies with individual agreements

Table 2-1. Ice road construction and maintenance equipment.

EQUIPMENT TYPE	QUANTITY	USE
Construction		
140 bbl Volvo Water Wagon or Caterpillar Water Buffalo	1	Haul water to the road construction site
150 bbl Water Truck	3	Haul water to the road construction site
16G Grader	1	Snow removal, berming, material movement
966 Loader with attachments	2	Load and unload materials and supplies
Crew Van	1	Crew transport
Fuel Truck	1	Support equipment fuel needs
Groomer	1	Smooth the route, breaks up hard pack snow
Heaters	3	As needed for crew and to keep pump house from freezing.
Light Plants	4	Light work areas
Mechanics Truck	1	Support equipment spread
Pump House	1	Pump water from the water sources into the water trucks
Seawater Pumps	5	Flooding for floating sea-ice roads
Volvo A35 Rock Truck, 25 cy	1	Hauling snow and ice chips
Maintenance		
Grader	1	Clear the road of snow
Heater	1	To keep the pump house from heating up
Light Plants	2	Light the start of the ice road and to light the pump house
Snow Blower	1	Clear the road of snow
Water Pump House	1	Pump water from the water sources into the water trucks
Water Trucks	2	Haul water to the road construction site

Table 3-1. Well plugging and abandonment equipment list.

EQUIPMENT TYPE	QUANTITY	USE
Operating		
Air Compressor	1	Air- line tests and air tool support
Crane Rigging Truck	1	Cables, straps, and shackles to support crane
Crane, 80-ton	1	Mobilize and demobilize equipment spread
Crew Boat	1	Personnel transport over open water, as needed
Crew Cab Pickup, ¾ to 1-ton	1	Personnel transport
Crew Van, 11-passenger	1	Personnel transport
Drilling Rig	1	Plugging and abandonment of wells
Flatbed Pickup, 1 to 2-ton	1	Material movement and personnel transfers
Food Waste Dumpster with lid	1	Food waste storage, bear-proof
Fuel Tank, 10,000-gallon	2	Contingency fuel supply and fuel transfers
Fuel Truck	1	Equipment support
Generator, 90 kw	2	Power support for non-self-powering equipment
Heaters, ES 700	3	Heat for equipment and personnel
Helicopter	1	Personnel transport and emergency response support
Light Plant	4	Work place lighting and power support
Loader, 966	1	Pad maintenance and downhole support
Lowboy with Tractor	1	Material resupplies
Man Camp, 24-person	1	Housing for overflow personnel on site
Mechanics Truck	1	Equipment support
Metal Dumpster	1	Construction debris storage
Rig Mats, 8 feet by 30 feet	10	Ramp and ground support for equipment spread
Super Sucker	1	Fluid handling and transfers, emergency response
Vacuum Truck	1	Fluid handling and hauling to and from site
Warm-up Shack	1	Guardhouse to control pad traffic, provide a muster area and provide a warm-up area for personnel
Wastewater Truck	1	Transfer human waste
Welding Truck	1	Support fabricating needs on location
Zoom Boom	1	Lift and move materials and equipment in and out of tight, hard to reach places.
Mobilization and Demobilization for Barging		
Barge	2	Mobilize and demobilize equipment
Crew Cab Pickup, ¾ to 1-ton	1	Personnel transport
Fuel Truck	1	Equipment support
Light Plant	4	Work place lighting and power support
Loader, 966 with attachments	2	Loading and offloading barges on the shore and on the island and maintaining barge ramps
Lowboy with Tractor	2	Mobilize and demobilize equipment spread and material resupplies to and from barge landings
Mechanics Truck	1	Equipment support
Tug Boat	2	Power barge for mobilizing and demobilizing equipment
Winch Truck	2	Loading and offloading barges on the shore and on the island

Table 3-2. Various kill weight fluid salt types and their related density and TCT.

SALT TYPE	DENSITY (PPG)	TCT (°F)
NaCl	9.8	-6
$KHCO_2$	10.3	-20
$CaCl_2$	11.0	-22
NaBr	11.7	-19
$CaBr_2$	12.0	-23
$CaBr_2$ / $ZnBr_2$	14.6	-21

Table 3-3. Seasonal downtime due to weather.

MONTH	DOWNTIME
January	20%
February	20%
March	15%
April	10%
May	10%
June	5%
July	5%
August	5%
September	5%
October	10%
November	10%
December	10%

Table 4-1. Subsea pipeline abandonment equipment list.

EQUIPMENT TYPE	QUANTITY	USE
Offshore Island Site		
Air Compressors, 1300-cfm	1	For pigging the pipeline
Air Compressors, 185-cfm	2	For unbolting and cutting pipeline
Break/Warm-up Shack/Office,	2	Rest break, warm-up
Crane, 80-ton, with Clam		Excavation of pipe
Crew Cab Pickups, ¾ to 1-ton	5	Personnel transport
Excavator, Large CAT 390 or equal	1	Excavation& backfill
Flat Bed trucks, 1 to 2-ton	1	Hauling materials, as needed
Fuel Truck, 5,000 to 10,000 gallons	1	Fuel equipment
Generator, 40-kw	1	Power for portable offices
Hand Tools, as needed (e.g. Rattle Gun, ¾-inch)	1	Miscellaneous
Helicopter	1	Fly Crews to island and general support
Loaders, 966 size	2	Backfill and material handling
Local Barge, 200 x60 feet	1	Mobilize and demobilize equipment and material
Local Tug	1	Mobilize and demobilize equipment and material
Lowboy with Tractor	1	Mobilize and demobilize equipment
Mechanics Truck/Oil Lube	1	Support equipment spread
Office, 14 feet by 40 feet	1	Office activities
Oxygen/Acetylene Industrial Torch Set with Gas	2	Cutting as needed
Pipe Cutting Equipment	1	Pipeline cutting
Portable Bathrooms (Envirovac)	2	Personal use
School Bus with Small Gen Set, 3 to 5-kw	1	Transport personnel, break, lunch, etc.
Tanker Trucks with Pumps	3	Store pipeline cleaning fluids
Vacuum Truck	1	Removal of pipeline cleaning fluids
Welding Truck with Welding Machine	2	Cutting and welding pipeline, as needed
Onshore Collection Site		
Air Compressors, 185-cfm	1	Unbolting and cutting the pipeline
Air Compressors, 900-cfm	1	Thaw frozen ground
Air Track Drill	1	Thaw frozen ground
Crew Cab Pickups, ¾ to 1-ton	5	Personnel transport
Excavator, Large: Cat 330 or equal	1	Excavation & backfill and lifting demo pieces
Heaters, 500 Mbtu	1	Area heating as required
Light Plants, 8 kw	2	Area lighting as required
Loaders, 966 size	1	Material handling
Lowboy with Tractor	1	Mobilize and demobilize equipment
Rolligon	3	Tundra access, haul excavator and material to the shore site.
Steamer Truck	1	Thaw frozen ground
Welding Truck with Welding Machine	2	Cutting and welding pipeline, as needed

Table 5-1. Structures and facilities removal equipment list.

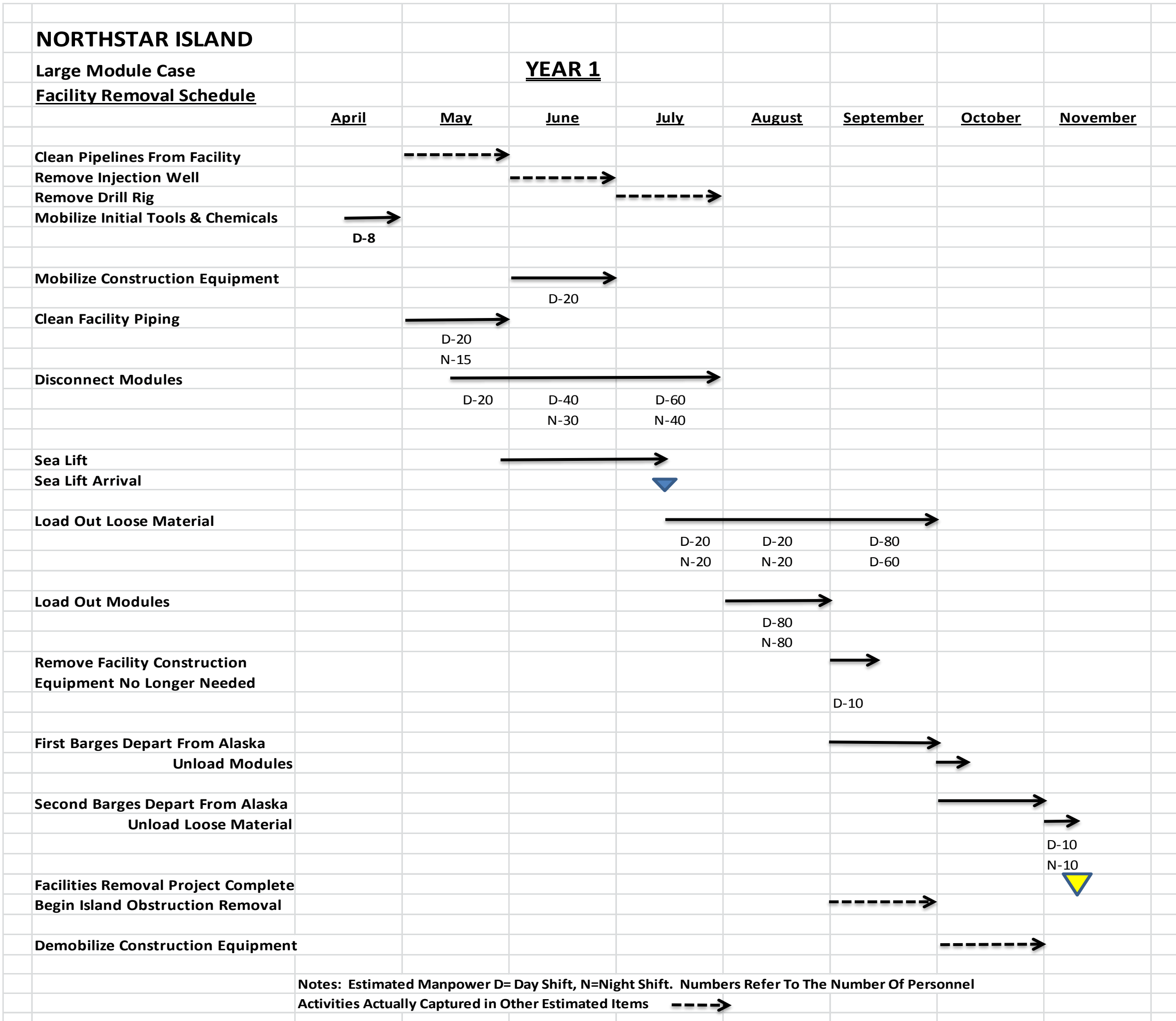
EQUIPMENT TYPE	QUANTITY	USE
Barge, 400 x 100	5	Sea lift barges
Break Shack	3	Crew support
Camp, 24-man	2	Crew Support
Crane, Crawler 250-ton	2	Lift smaller modules and ancillary material, load barges
Crane, Crawler 300-ton	2	Load out smaller modules if required
Crane, Hyd 45-ton	2	Lift ancillary material
Crew Cab Pickup Truck	6	Crew support
Envirovac	2	Crew support
Flatbed Trailers, 20-ton capacity	4	Transport ancillary material
Fuel Truck	1	Equipment support
Generator 150-kw	4	Crew support
Generator 25-kw	2	Crew support
HD Tractors, 5 wheel	3	Transport small modules and ancillary material
Heavy Duty Lowboy Trailers, 150-ton	3	Transport small modules and ancillary material
Heavy Duty Self Propelled Module Transporters (SPMT)	1 lot	Lift and transport large modules
Helicopter	2	Crew transportation and emergency response
Hot Water Truck	1	Thaw frozen ground, help cleaning process
Light Plants	2	Area work lighting
Loaders, 966 type	3	Material handling
Loaders, 988 type	1	Material handling
Local Barge, 100 x 60 feet	3	Local barges, mobilization/demobilization
Lube Truck	1	Equipment support
Manlifts, 56 feet	4	Used to access disconnect points
Mechanics Truck	1	Equipment support
Potable Water Truck	1	Camp support
Sewage Truck	1	Camp support
Tanker Trucks, 300-bbl	3	Handle fluids in process plant
Tractors, 5 wheel	2	Transport ancillary material
Tugs, Seagoing	3	Sea lift
Tugs, Shallow Draft	4	Local barges and sea lift barge support
Vacuum Trucks	1	Handle fluids in process plant
Welding Machines	6	Weld temporary bracing
Work Boat, 50-passenger	1	Crew transportation

Table 6-1. Obstructions, stabilization structures, and armoring removal equipment list.

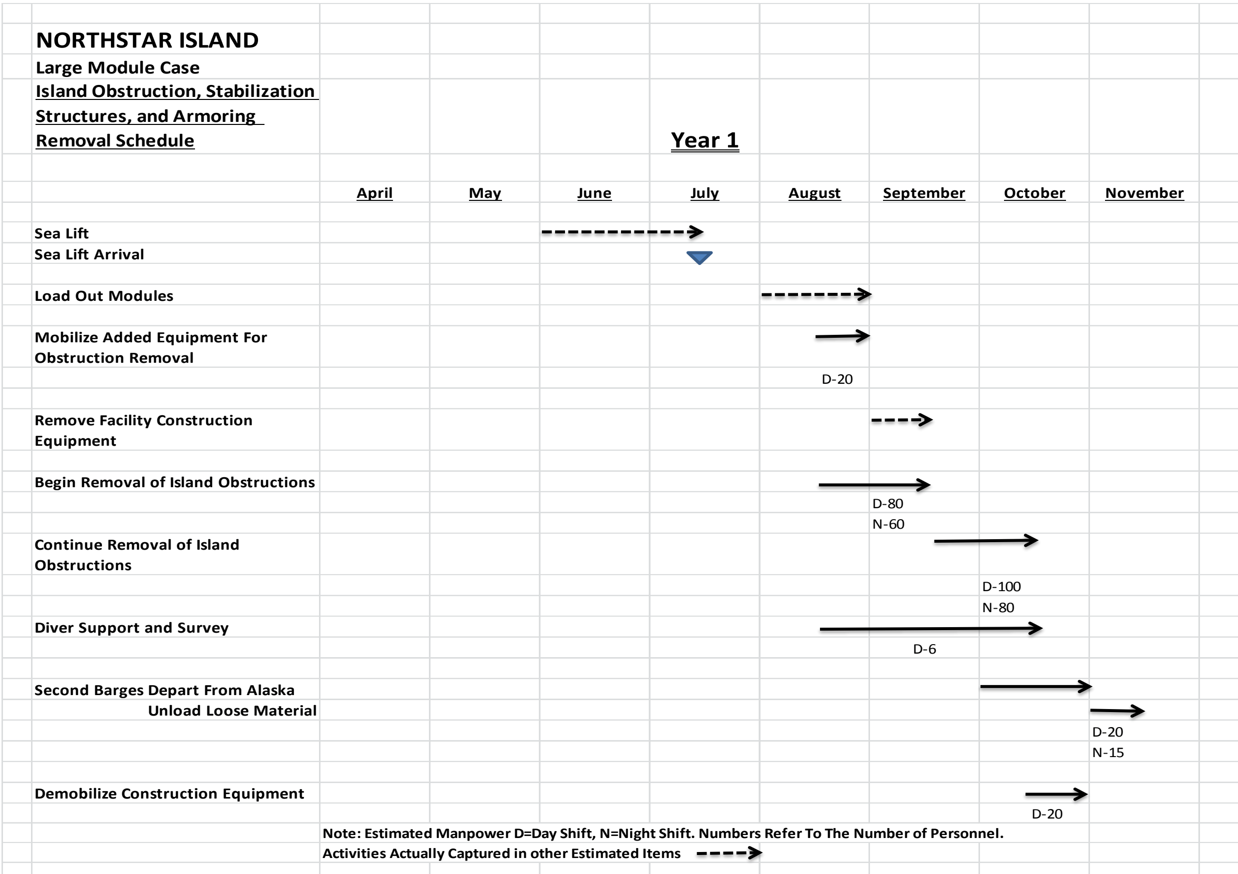
EQUIPMENT TYPE	QUANTITY	USE
Tractor, 5 wheel	6	Material handling
Break Shack	3	Crew support
Bulldozer, D-8	3	Re-grade island profile
Camp, 24 bed capacity	2	Crew support
Crane, 45-ton Hydraulic	1	Material Handling
Crane, Crawler 250- ton	2	Lift concrete mats and foundations, pull pipe and sheet piling, load out barges
Crane, Crawler, 80-ton with drag bucket	1	Pull up fabric and geotech barriers on island slopes
Crew Boat, 50 pass	1	Crew transport
Crew Bus, 30 pass	2	Crew transport
Crew Cab, pickup	6	Supervision and personnel transport
Envirovac	2	Crew support
Excavator, Cat 330 or equal	1	Excavate foundations and piling
Excavator, Cat 390 or equal	2	Excavate foundations and piling
Flatbed Trailer	4	Material handling
Fuel Truck	1	Equipment support
Generator, 150 kw	4	Camp power
Generator, 25 kw	4	Power supply
HD tractor, 5 wheel	1	Mobilization and demobilization of equipment
Helicopter	1	Crew transport and Emergency Response
Helicopter, 11 passenger	2	Transport crew and Emergency Response
Hot Water Truck	1	Thaw frozen pilings and conductors
Hydraulic Jack Set, 500- ton capacity	1	Extra pulling force for difficult piling and conductors
Light Plants, 8 kw	2	Area lighting
Loader, 966	3	Material Handling
Loader, 988	1	Material Handling
Local Barge, 200 x 60 feet	4	Mobilization and demobilization of equipment, material
Local Shallow Draft Tugs	4	Mobilization and demobilization of equipment, material
Lowboy Trailer, 150-ton	1	Mobilization and demobilization of equipment
Mechanics Truck	1	Equipment support
Potable Water Truck	1	Camp support
Sea going Barge, 400 x 100 feet	4	Transport scrap to Seattle
Sea Lift Tug, 400 x 100 feet	3	Sea Lift back to Seattle
Seagoing Tugs	2	Transport scrap to Seattle
Service/Lube Truck	1	Equipment support
Sewage Truck	1	Camp support
Steamer Truck	1	Thaw frozen piling and conductors
Tanker Truck	2	Fuel Storage
Vibratory Pile Hammer/Extractor	1	Pull sheet piling
Workboat, 50 passenger	1	Transport crew to island

APPENDIX B: SCHEDULES

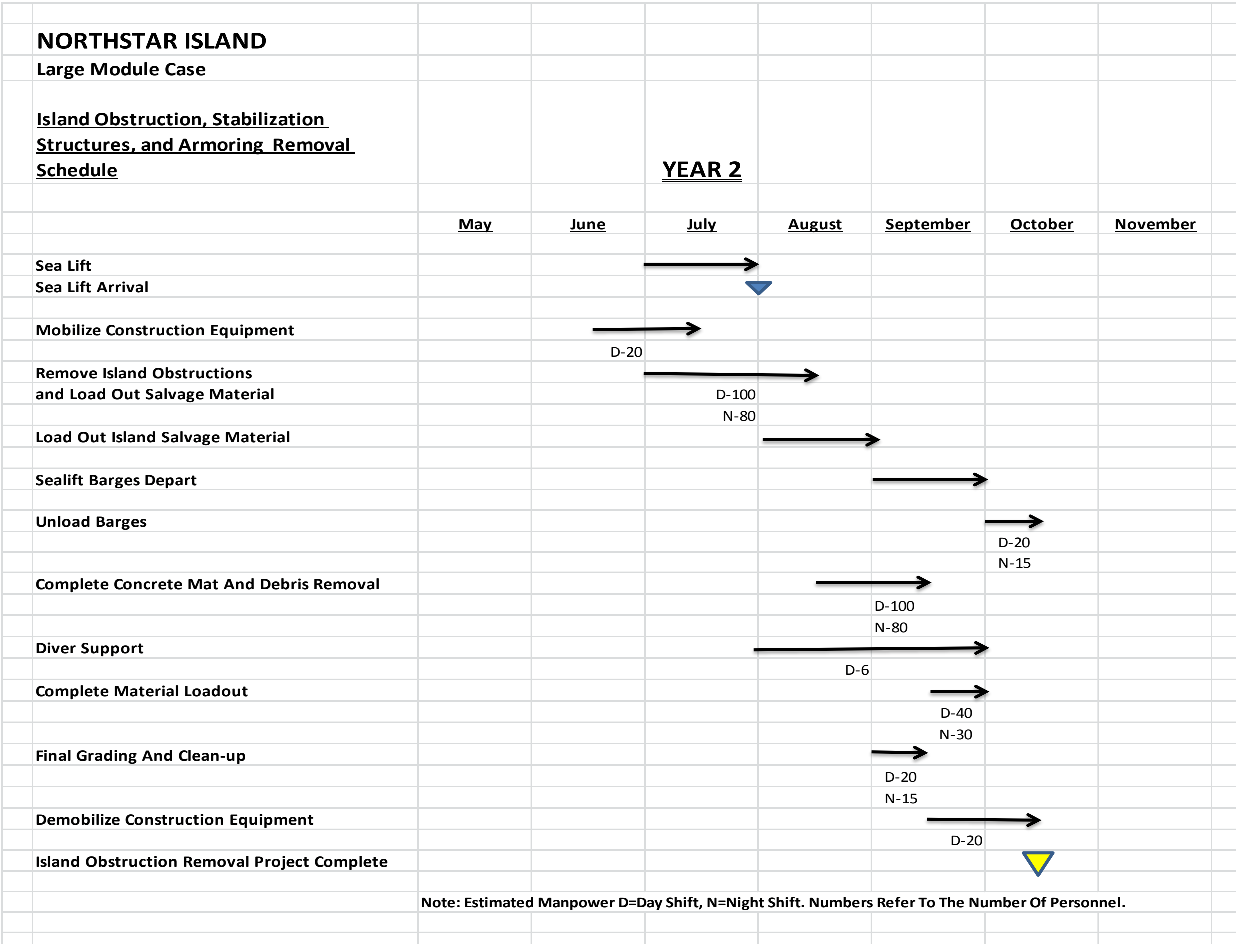
Schedule 1: Northstar Island Large Module Case for Facility Removal.



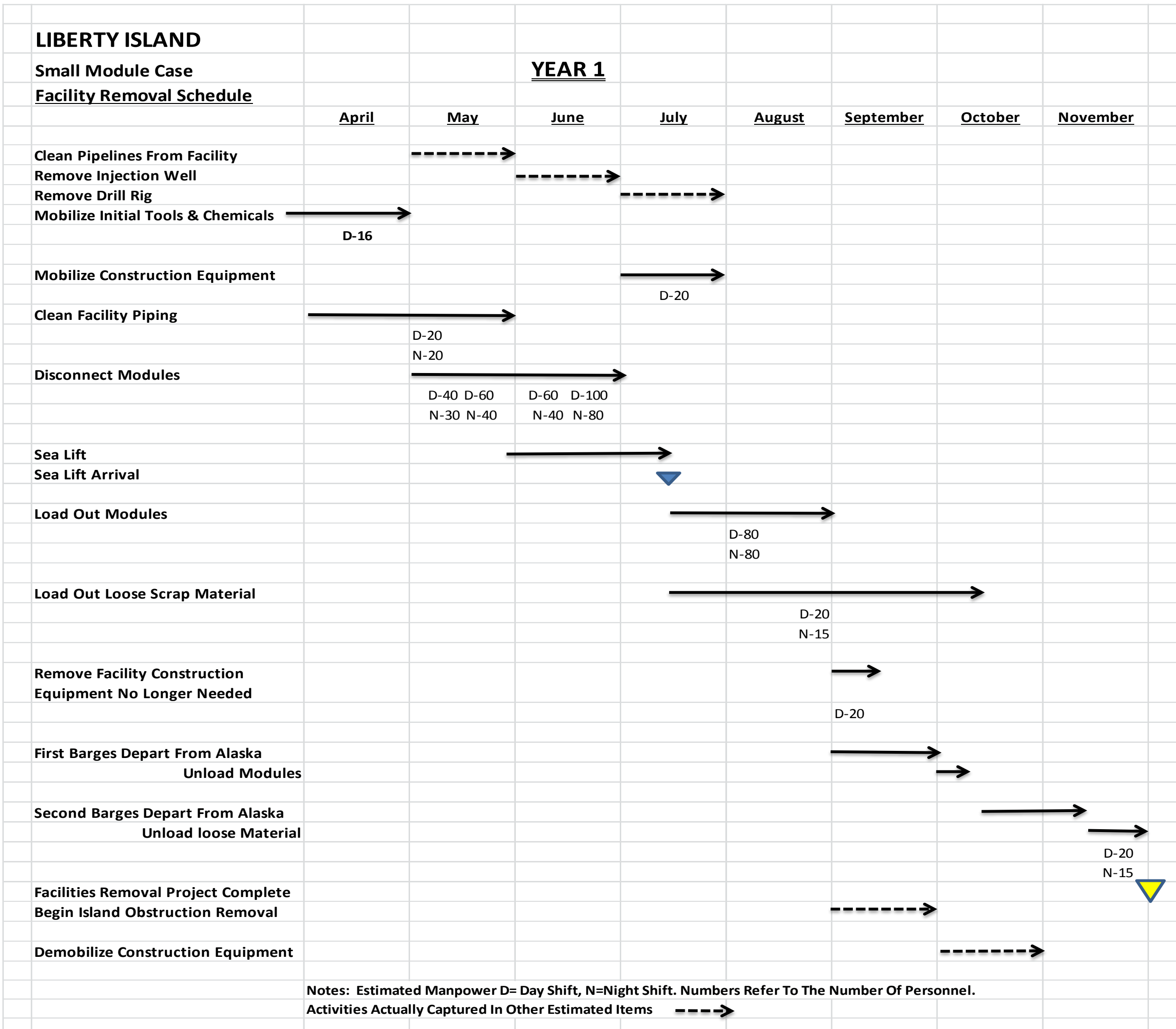
Schedule 2: Northstar Island Large Module Case for Island Obstruction, Stabilization Structures, and Armoring Removal - Year 1.



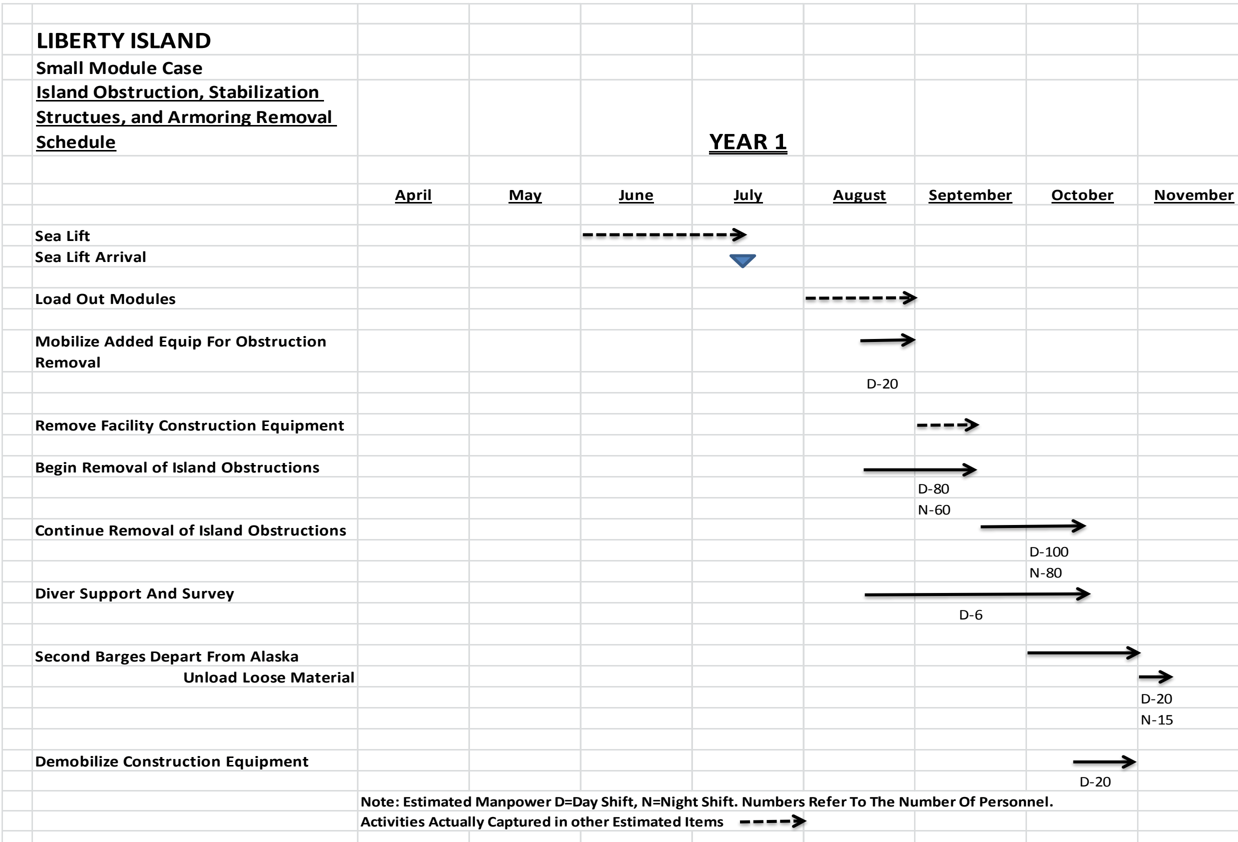
Schedule 3: Northstar Island Large Module Case for Island Obstruction, Stabilization Structures, and Armoring Removal - Year 2.



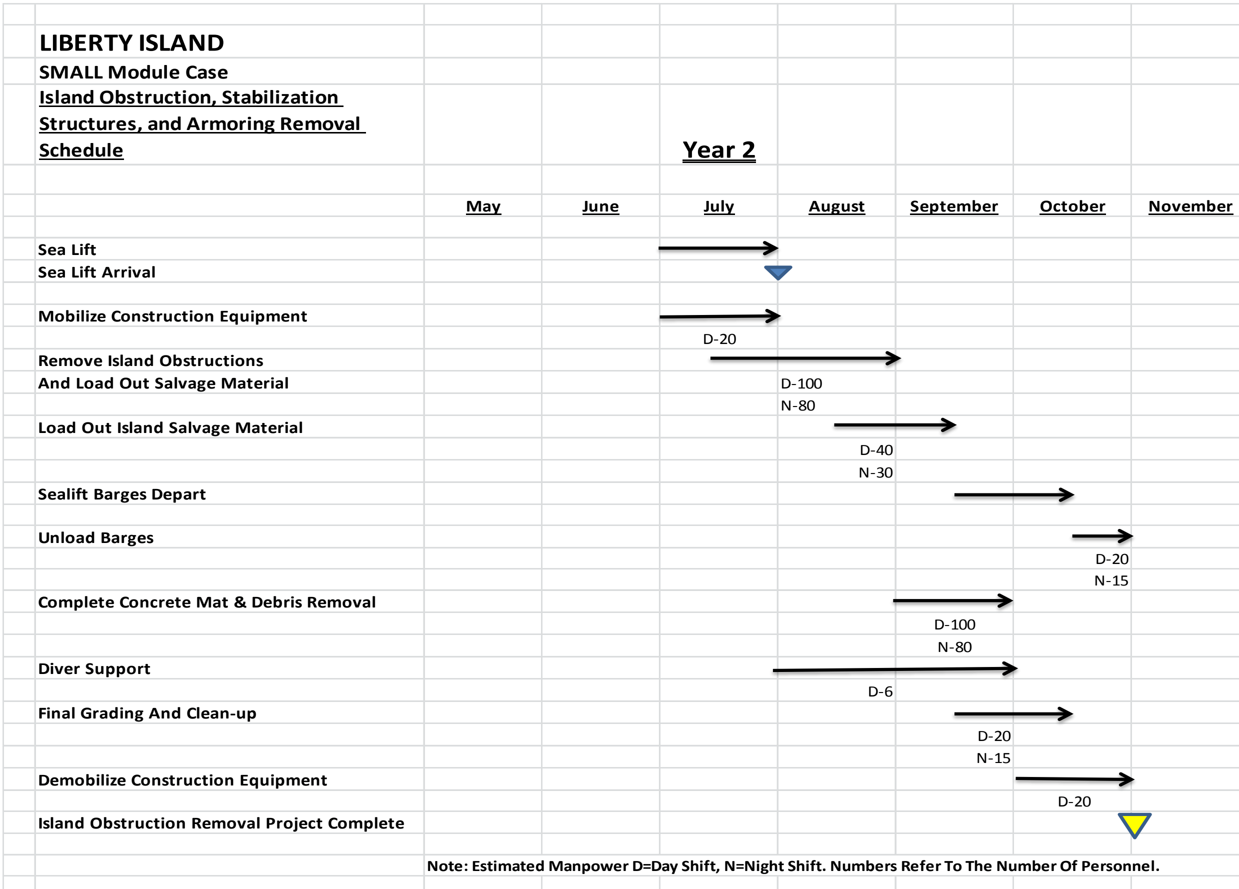
Schedule 4: Liberty Island Small Module Case for Facility Removal.



Schedule 5: Liberty Island Small Module Case for Island Obstruction, Stabilization Structures, and Armoring Removal - Year 1.



Schedule 6: Liberty Island Small Module Case for Island Obstruction, Stabilization Structures and Armoring Removal - Year 2.



APPENDIX C: CONTRIBUTOR QUALIFICATIONS

Contributor Qualifications 1: Lucas Munisteri

Lucas Munisteri, P.E.

lucas.munister@solstenxp.com
907-264-114

Summary

I am a highly self-motivated engineer with an exceptional learning curve and thrive on being challenged. I hold myself to the highest of standards. The wells that I have planned and executed show the level of detail that I put into my work. By holding myself to the highest of standards, afforded me the opportunity to define how BP will drill the next generation of HPHT wells. Throughout my career, my attention to detail has put me in the position to define business best practices in a verity of organizations.

Experience

SolstenXP – Anchorage, Alaska

Drilling Engineer **Feb 2015 - Present**

- Successful planned and executed the abandonment of remote wells in the National Petroleum Reserve - Alaska on behalf of the US Bureau of Land Management.
- Developed procedures and a cost model for the abandonment of gravel islands in the Arctic Outer Continental Shelf.
- Planned and designed two well exploration drilling program on the west side of the Cook Inlet.
- Completed a rig startup, capability and refurbishment assessment for the Steel Drilling Caisson MODU to bring the unit out of long term storage and provided a current cost to complete this project.
- Identified a drilling rig in the lower 48 that could be brought to Alaska and used to drill wells on the North Slope that only required winterization for Artic conditions.
- Implemented a standardized system for tracking field operations to provide consistency in field performance and record keeping to improve well archives.
- Assisted in a market analysis for determining the fire sale price of a 3,000 hp rig to be built and brought to the Cook Inlet for development drilling.
- Successfully drilled a remote exploration well in the Arctic to prove possible reservoir location and size while managing complex environmental factors.
- Performed engineering analysis both onsite in the field and an office setting to manage the complex discoveries associated with drilling exploration wells.

Contributor Qualifications 1: Lucas Munisteri continued.

BP – Houston, Texas
Drilling Engineer Project 20K™ Oct 2013 - Feb 2015

- Through history matching past drilling data, I was able to build a detailed well model. A model I scaled to the limit and used to specify the necessary hook load and mud system requirements for new MODU design. The MODU is to be used to run industry benchmarking casing strings to industry-leading depths.
- Worked in a multi-disciplinary team on HPHT wells to develop technology and equipment to unlock future developments.
- Determined minimum relief well requirements through detailed dynamic well kill modeling work in Olga-ABC which resulted in a casing redesign.
- Collaborated with vendors for the development of an industry first landing string capacity.

BP – Houston, Texas
Well Placement Technical Specialist Feb 2013 - Oct 2013

- Responsible for the safety of all BP-operated wells to prevent well collisions.
- Managed the directional placement of all BP-operated and heritage company wells drilled in the Lower 48.
- Developed standard procedures for the Lower 48 for Well Placement and Anti-Collision requirements and by working directly with the regions that were impacted by the changes. I obtained their agreement to follow the new procedures. Due to the comprehensiveness of the procedures, they were used as the standard template globally.
- Integrated drilling database software across geological and reservoir platforms for increased efficiency and interdisciplinary collaboration. Aimed to reduce well planning time.

BP – Houston, Texas
Drilling Engineer Cotton Valley Jun 2012 - Mar 2013

- Successfully drilled horizontal wells while reducing costs through identifying sections of the well design that could be optimized through the application of RSS in the curve and horizontal well sections.
- Recovered $250,000 from vendor due to tool failure through a root cause analysis of failures and drilling parameters.
- Identified $500,000 in overspend in SAP vs. OpenWells per well, and worked with field personnel to improve cost reporting.
- Reviewed three years well cost history and developed probabilistic AFE's to permit wells at P50, which reduced the number of wells that went over AFE.
- Reduced the well planning time from 2 weeks to hours, and minimized directional work required in the lateral when geosteering, by working directly with the geologist when planning the well path in the geological model. Led to Helios Finalist Award for Excellence, a company-wide recognition for technical excellence.

Contributor Qualifications 1: Lucas Munisteri continued.

BP – Houston, Texas
Drilling Engineer Woodford **Mar 2012 - Jun 2012**

- Successfully drilled horizontal wells reducing cost by reducing NPT to less than 10% through proper contingency planning.
- Successfully drilled lateral section without any wellbore stability issues.
- Lateral was stable for 14 days through multiple logging trips.
- Ran multiple logging tools to validate cutting-edge technology for future deployment.
- Created an adaptive program to account for operational changes and revised the procedures in the field, real time.

BP – Houston, Texas
Drilling Engineer San Juan **Dec 2010 - Mar 2012**

- Restarted drilling program by performing comprehensive well control analysis with DrillBench Kick, resulting in a region specific deviation from well control procedures.
- Directed T3 engineers to design a BOP that was less then 8' tall due to rig constraints, requiring a redesign of BOPe to meet height and pressure requirements.
- Worked with office and field staff to develop a workflow to improve the permitting process, reducing time worked from 3 months to 3 weeks, through eliminating inefficiencies in the process. Cut costs through reducing the number of premature negotiations with landowners for unused drill sites.

BP – Stuart, OK
Field - Drilling Engineer **Apr 2010 - Dec 2010**

- Managed the drilling performance of 5 rigs in real time.
- By monitoring the torque and drag and comparing it with modeled values, I recommended actions for the rig to take to prevent stuck pipe incidents, reducing sidetracks.
- Worked with drillers to improve their understanding of the stuck pipe indicators.
- Transfer learnings from the field into the office to improve procedures.

BP – Wamsutter, WY
Field Drilling Engineer **Jun 2009 - Apr 2010**

- Performed task of a night well site leader:
  - Entered operational summary into OpenWells.
  - Strapped casing and built casing tally.
  - Calculated cement volume and displacement volume.
  - Monitored cement displacement to verify success placement of cement.
  - Performed cement calculations.
- Developed a standard tool for comparing real-time drilling data to modeled data.

Norwest Corporation – Golden, CO
Petroleum Technician **Jan 2008 - May 2009**

- Reviewed and updated original drilling manual for new standards and technology.

Contributor Qualifications 1: Lucas Munisteri continued.

- Verified vendors analysis of new technology for microbial enhanced oil recovery performance.
- Performed a stimulation analysis in Wyoming to identify the fracture type and service company that had the best return on investment.
- Coded a tool to be used for tracking oil and gas price.

Hathaway, LLC – Bakersfield, CA
Intern Drilling Engineer **Jul 2008 - Aug 2008**

- Planned directional well profiles for Newfield Exploration and ConocoPhillips for execution.
- Worked closely with companies to design a rechargeable battery for shallow low-temperature operations.
- Researched a new field that the company had recently purchased to determine the remaining reserves and then what could be done to recover the oil in place. I was within 10% of the size of the field, and the field was returned to production.

Patriot Resources, LLC – Carpinteria, CA
Intern Intervention Engineer **Jun 2008 - Jul 2008**

- Performed an intervention on a well that was producing excess water and successfully identified the water zones.
- Prepared AFE for operation.
- I ran a bridge plug and a tension set packer on a double fast line rig.
- I performed a pressure test on the well to identify water zones.
- I planned a cement job to remediate the water zones.
- The job came in under AFE.

Patterson-UTI – Parachute, CO
Floor Hand **Jun 2007 - Aug 2007**

- Held pre-job safety meetings.
- Supported physical tasks required to drill the well; making connections, racking pipe, and strapping pipe.
- Maintained the drilling rig to keep it in good shape; checking electrical connections, maintaining fluids, and painting rig.
- Assisted company man with special operations such as counting cement displacement and monitoring logging operations.
- Performed through drill pipe coring and impromptu video log to identify the source of the losses.

Contributor Qualifications 1: Lucas Munisteri continued.

Education

BP Proprietary Training Program Houston, TX

BP Advanced Well Control, Applied Deep Water Well Control, Casing Design & StressCheck, Tubing Stress Analysis & WellCat, Managing Hole Problems, Loss Circulation Mitigation, Well Positioning, Surveying & Compass, Cementing

Industry Training Houston, TX

Drilling Training Alliance	Well Planning, Drilling & Completions Fluids, Solids Control, Cementing, Environmental Management for Drilling Engineers, Integrity Management Fundamentals, Well Productivity Awareness, C-Wear, Completion Design, Fishing Operations, Directional, Horizontal & Multilateral Drilling
TH Hill	Drill String Design
PetroSkills	Basic Petroleum Geology, Well Log Interpretation
Halliburton	Bit Design and Optimization, Drilling Fluids, Landmark Suite
SPT	DrillBench Kick
DGI	CoViz, EarthVision, Well Architect
FEMA	ICS 100

Colorado School of Mines

Golden, CO May 2009

B.Sc. Petroleum Engineering
Major GPA: 3.29/4.0,
Certificate in Science, Technology, Engineering, and Policy

Affiliations, Certificates & Skills

- Professional Engineering License #118948 in State of Texas — Dec 2014 – Present
- Professional Engineering License #TBD in State of Alaska Conditionally Approved Pending Artic Engineering Course
- IADC Drilling Surface and Subsea Well Control — Feb 2018
- HUET Training — Oct 2013 – Present
- TWIC Card — Jan 2019
- Microsoft Office 2013,
- Excel VBA
- LandMark's Well Planning Suite
- SPT's Well Planning Suite
- WellEZ, Tableau
- AutoCAD

Contributor Qualifications 2: Bill Morrow.

William Morrow P.E., PMP

bill.morrow @solstenxp.com
907-279-6900

Summary

Over forty years of experience in the engineering and construction of various projects in diverse industries which include liquified natural gas, oil refining, petrochemical oilfield production and treatment, pipelines, water treatment, fertilizers, pulp and paper, iron and steel, and power and transmission. Also experienced in construction management, commercial, and heavy civil construction practices and procedures. Have progressed through various field construction assignments from construction engineer to superintendent to various home office assignments such as Manager of Project Services, Manager of Estimating & Proposals, Project Manager, Vice President and President. Experienced in various job costing methods, financial packaging, labor management, construction methods, project scheduling, estimating, and executing projects in diverse climatic conditions.

Experience

Morrow & Associates – Anchorage, AK

President **Aug 2005 - Present**

- Provide construction and program management consulting services to include Project Management, Estimating, Proposal development, labor relations, Project Controls, Inspection, Contract Administration and development, construction claims, dispute resolution and legal assistance.

Norcon, In., a VECO Company – Anchorage, AK

President **Oct 2001 – Aug 2005**

- Responsible for all of the company operations and financial performance of the union construction arm of VECO Corporation in Alaska. Responsible for the Health, Safety and Environmental performance of all the Company's operations. Responsible for the management of all projects and estimates. Responsible for all personnel. Responsible to negotiate all labor agreements. Projects include North Slope maintenance and new construction for facilities, pipelines, well lines, drill sites, and power distribution for BP. Norcon also performed electrical utility work throughout Alaska for various utility clients that included power distribution, substations, transmission lines, communications and controls including fiber optics. Norcon also performed all electrical work for the Stryker Training areas at Ft. Richardson and Ft. Wainwright for the US Army. Norcon also produced the design of the high voltage distribution system for the Ft. Richardson project.

Contributor Qualifications 2: Bill Morrow continued.

VECO – Anchorage, AK

Vice President, Project Support Services **Jan 1997 – Sept 2001**

- Responsible as focal point for corporate assistance, evaluation and approval for major projects requiring corporate involvement. Assist in the management of corporate projects as required and assigned. Responsible for the corporate estimating and project management systems and procedures. Assisted in overall project management and reviews on major projects undertaken by the Corporation. These included the Cogen project at Meridian for Husky Oil and TransCanada; the Cogen project for Cancarb at Medicine Hat, Alberta; the Cogen project for AEG & T at Nikiski, AK; the refinery modernization for Coop at Regina, Saskatchewan; a recovery boiler at Powell River, BC; the Liberty Island Oil Field Development at Prudhoe Bay; and the Alaskan Gas Pipeline conceptual studies.

VECO Construction – Anchorage, AK

Senior Estimator & Manager of Estimating & Engineering **Apr 1987 – Apr 1997**

- Manage Estimating Department personnel in the development of time and material, lump sum, and cost plus bids for oilfield construction work. Monitor, report and control cost and scheduling activities. Also served as Project Manager on various projects such as BP Alaska's Y-Pad Module Fabrication project, BP's Mukluk Island Abandonment project in Prudhoe Bay, and gas processing plants and pipelines for Unocal's Cannery Loop #1 and #3 project in Kenai, Alaska. The Mukluk Island Abandonment project included removal of armor bag protection, 42" drill conductors and 16' cellar boxes, concrete dock blocks, and regrading the offshore island. The Cannery Loop Project consisted of installation of process equipment, piping, electrical, and concrete works at two drill sites and the 8" pipelines to connect to the Enstar pipeline system.

Frontier Companies of Alaska – Anchorage, AK

Manager of Industrial Estimating & Engineering **1985 - 1987**

- Responsible for the preparation and assembly of all Industrial Division estimates and proposals. Familiar with lump sum, unit price, cost plus, open cost, and technical proposal preparation. Prepared project procedures including Quality Assurance, subcontracting, scheduling, and cost control.Prepared project schedules and budgets. Established construction equipment requirements. Performed as Project Manager for assembly of SAPC's Nitrogen Bottling Facility in Anchorage, the first truckable module designed and built in Alaska for Prudhoe Bay. Bid projects up to 25 million dollars.

Kellogg Rust Constructors – Houston, TX

Manager of Estimating & Proposals **1982 - 1985**

- Responsible for the preparation and development of all construction estimates and proposals for the company. Supervised the preparation of all marketing information and graphic aids for company proposals, presentations and pre-qualifications. Prepared

Contributor Qualifications 2: Bill Morrow continued.

concept cost studies. Supervised the bidding of major worldwide projects up to 6 **billion** dollars. Projects included LNG, Ammonia, Urea, Fertilizer, Refinery, FCCU revamps, petrochemical, pulp and paper, micro-chip, modular oil processing, material handling and power in the North American and International markets both for new construction and revamps and modernizations. Participated as Kellogg Rust's representative on the formation and beginning projects of the Construction Industry Institute (CII).

Kellogg Rust Constructors – Houston, TX

Manager of Project Services **1981 - 1982**

- Responsible to provide construction cost and engineering services to Hackensack, N.J. branch office. Developed estimates, budgets, schedules, and progress reports. Prepared rigging studies, quality assurance programs, welding engineering, and temporary facility requirements. Analyzed productivity and schedule trends. Assisted in preparation of claims and change orders. Performed as Project Construction Manager for projects assigned. Projects included four Flue Gas Scrubber projects for large Power Plants in Missouri, Arizona, Indiana and Kentucky; phenol plants in Ohio and Argentina, Refinery projects in Argentina and Colombia and Ammonia Plants in India, Indonesia and Argentina

Kellogg Rust Constructors – Houston, TX

Construction Superintendent **1979 - 1981**

- Responsibilities included supervising all field construction activities in area assigned. Allocated manpower, material and equipment to meet schedule and budget requirements. Maintained site labor relations and made craft work assignments. Implemented safety programs and practices. Ensured work was performed in accordance to drawings and specifications and that required inspections were made. Supervised up to 450 craft and staff personnel. Projects included a Phenol Plant in Indiana for GE and an Ammonia Plant for Amoco in Trinidad.

Kellogg Rust Constructors – Houston, TX

Chief Field Engineer **1975 - 1979**

- Responsible for the technical quality of construction through the monitoring of construction activities and the interpretation of specifications, standards and drawings. Assisted field supervision in planning work. Responsible to ensure required inspections and tests were performed. Responsible for cost and scheduling of the project. Provided field design services as required. Administered and let subcontracts. Projects included a grassroots Ammonia-Urea Fertilizer Plant in Indonesia.

Kellogg Rust Constructors – Houston, TX

Assistant to Construction Manager **1974 - 1975**

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Contributor Qualifications 2: Bill Morrow continued.

- Responsible to assist Home Office Construction Manager in managing of projects assigned. Assisted in the pre-project planning of projects including assignment of personnel and establish construction equipment requirements and sources, assisted in the preliminary scheduling of personnel, material and equipment and expedited resolutions to field problems. Coordinated field construction requirements on all projects assigned with engineering and procurement departments.

Kellogg Rust Constructors – Houston, TX

Construction Engineer **1973 - 1974**

- Responsibilities included supervising civil and mechanical subcontractors, ensure all work was performed according to drawings and specifications, resolved field problems and interpreted drawings, established working schedules consistent with overall project requirements, provided material control.

Texaco Inc. – Lawrenceville, IL

Maintenance Engineer **1972 - 1973**

- Duties included providing design, estimating, scheduling, and subcontract administration services to refinery. Supervised maintenance projects; projects included modifications and revamps, unit turnarounds, new unit and infrastructure installation, and repair projects.

U.S. Army Corps of Engineers – Stuffgart, Germany

First Lieutenant **1970 - 1972**

- Responsible as the Platoon Leader for the supervision and management of a construction earthmoving platoon on constructing various roads, tank farm, rifle range and sports complex projects throughout Germany. Promoted to Assistant Battalion Operations Officer (S-3) responsible for the design, survey, cost control and construction activities of all construction projects performed by the Battalion.

C & M Construction – Wheeling, IL

Laborer / Engineering Assistant **1965 - 1970**

- Worked on various underground utility relocation and improvement projects in the Chicago area for the telephone and utility companies. Worked on installation and cleanup of storm drainage and curb systems on highway construction projects. Worked as engineer's assistant on construction of 320 mile 36" natural gas pipeline from Mahomet, IL to Chicago

Education

University of Illinois	BS Civil Engineering
University of Alaska, Anchorage	Arctic Engineering

Contributor Qualifications 2: Bill Morrow continued.

Affiliations, Certifications & Skills

- Professional Engineer, Civil License # 9600 in State of Alaska
- Mechanical Administrator License # 578 in State of Alaska
- Project Management Professional (PMP), PMI, 02102

- Project Management Institute
- American Society of Civil Engineers
- American Association of Cost Engineers
- American Society of Professional Estimators
- International Association of Plumbing and Mechanical Officials

Contributor Qualifications 3: Charlotte MacCay

Charlotte MacCay

charlotte.maccay@solstenxp.com
907-264-6124

Summary

Twenty five years of experience in Environmental Management and Permitting, specializing in large-scale natural resource development. Expertise includes NEPA process/reviews and permitting; compliance management; and baseline studies development. Strong communication skills and experience with stakeholder outreach, corporate, public, government, and Native relations.

Experience

SolstenXP – Anchorage, Alaska

Senior Permitting Manager **Jan 2015 – Present**

- Aurora Gas – Gas exploration permitting
- Chuitna Coal Mine Inc. – EIS Review and Comment/Stakeholder Outreach

Owl Ridge Natural Resource Consultants – Alaska

Senior Permitting Manager **Mar 2014 – Sep 2014**

- Royale Energy, Inc. – Oil and gas drilling exploration permitting and stakeholder outreach on the North Slope
- Doyon, Limited - Seismic exploration program in the Nenana Basin
- Usibelli Mine Inc. – Coal bed methane exploration permitting in Healy Creek

Pebble Limited Partnership – Alaska

Director, NEPA & Permitting **2007 – 2013**

Directed all activities related to NEPA and permitting for a large open pit mine, road power plant and port facility:

- Primary contact with state and federal agencies for all permitting and baseline studies.
- Development of NEPA documents – Statement of Purpose and Need, Project Description, Baseline Studies Document, Alternatives Information Database, Wetlands Mitigation Options Database
- Preparation of all permit applications and preliminary plans – Reclamation Plan, Conceptual Mitigation Plan
- Participated in stakeholder outreach presentations and materials preparation
- Review of scope and methodology guidance for baseline studies

Contributor Qualifications 3: Charlotte MacCay continued.

Alaska Gold Nome Operations / Bristol Environmental & Engineering Services – Alaska
Environmental Manager 2003 - 2007

Provided stakeholder outreach, permitting, compliance, and remediation oversight.

- Acquired all permits to support construction of the Rock Creek gold mine and mill in Nome, Alaska
- Managed all environmental and social baseline studies for the Rock Creek Mine and compiled an extensive Environmental Document to support the NEPA process
- Managed hazardous waste and fuel clean-up for historic mining properties
- Public relations and agency contact, planned all public meetings, wrote weekly newspaper column

Chuitna Coal Project / Bristol Environmental & Engineering Services – Alaska

Coastal Consistency Project Manager 2007

- Prepared a comparative analysis to demonstrate compliance with Coastal Zone Management Policies for a large coal mine, and export terminal in south-central Alaska.

Northern Dynasty, Pebble Project / Bristol Environmental & Engineering Services – Alaska

Permitting Advisor 2004 - 2007

Provided NEPA, permitting, and stakeholder outreach expertise for the Pebble Project:

- Participation in strategic planning meetings for baseline and permitting programs;
- Coordination of all regulatory technical working groups
- Participated in regional stakeholder outreach programs

Red Dog Mine – Kotzebue, Alaska

Senior Administrator of Environmental Affairs 1991 - 2003

Managed all environmental and social aspects of the Red Dog Mine, a large open pit zinc mine, road and port operation near Kotzebue, Alaska, including:

- Fostering trust and improving relationships with Native corporation landowners and the public
- Expediting permit acquisition through problem resolution with state and federal agencies
- Lobbying and testifying in development of relevant state regulations and statutes
- Managed all environmental permit and compliance programs

Contributor Qualifications 3: Charlotte MacCay continued.

Education

Oak Ridge Universities (Research Grant) 1981	Conducted research on the feeding preferences of conch offshore in Mayaguez, Puerto Rico
Huxley College of Environmental Studies **Western Washington University, Bellingham 1982**	B.S., Environmental Studies, Ecosystems Management and Assessment
Pacific Oaks College, Pasadena, California 1986	Graduate Coursework in Education, K-8 Teaching Certification

Affiliations, Certifications & Skills

- Alaska Minerals Commission 1999 - 2013
- Governor's Transition Team on Environmental Conservation (2006, 2002)
- State of Alaska NPDES Primacy Workgroup (2005)
- State of Alaska Air Permits Work Group (2002)
- State of Alaska Task Force on Motorized Oil Transport (2001)
- State of Alaska Stream Reclassification Guidelines Workgroup (1996)
- U.S. EPA/State of Alaska Watershed Development Workgroup (1996)
- Alaska Miners Association
- Resource Development Association – HIA workgroup
- Endangered Species Act (2011)
- Wetlands Delineation Training – Richard Chinn Environmental Training (2004)
- Environmental Mediation – Resource Solutions, University of Alaska (2003)
- Alaska Mineral and Energy Resource Education Fund Training (2003)
- Systematic Development of Informed Consent – Institute for Participatory Management and Planning (2001)
- Environment Management Systems Audit Training - SENES (2000)

ACRONYMS

ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
ADOA	Alaska Department of Administration
API	American Petroleum Institute
BLM	Bureau of Land Management
BOP	Blowout Preventer
BOPe	Blowout Preventer (BOP) and the Associated Equipment
BP	British Petroleum
BSEE	(US) Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
EPA	(US) Environmental Protection Agency
FAA	Federal Aviation Administration
IWCF	International Well Control Forum
LOA	Letter of Authorization
MLLW	Mean Lower Low Water
NMFS	National Marine Fisheries Service
OCS	Outer Continental Shelf
SPMT	Self-propelled Module Transport
TCT	Typical Crystallization Temperature
USACE	US Army Corps of Engineers
USCG	US Coast Guard
USDOT	US Department of Transportation
USFWS	US Fish and Wildlife Service
WLRBP	Wireline Retrievable Bridge Plug

ABBREVIATIONS

bbl	barrel
bpm	barrels per minute
cfm	cubic feet per minute
cy	cubic yards
kw	kilowatt
ppg	pounds per gallon
psi	pounds per square inch

DEFINITIONS

Archaeological interest means capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurement, controlled collection, analysis, interpretation, and explanation.

Archaeological resource means any material remains of human life or activities that are at least 50 years of age and that are of archaeological interest.

Data means facts and statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Development means those activities that take place following discovery of minerals in paying quantities, including but not limited to geophysical activity, drilling, platform construction, and operation of all directly related onshore support facilities, and which are for the purpose of producing the minerals discovered.

Director means the Director of BSEE of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

Exploration means the commercial search for oil, gas, or sulphur. Activities classified as exploration include but are not limited to:

(1) Geophysical and geological (G&G) surveys using magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling conducted for the purpose of searching for commercial quantities of oil, gas, and sulphur, including the drilling of any additional well needed to delineate any reservoir to enable the lessee to decide whether to proceed with development and production.

Facility means:

(1) As used in §250.130, all installations permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). They include mobile offshore drilling units (MODUs) or other vessels engaged in drilling or down-hole operations, used for oil, gas or sulphur drilling, production, or related activities. They include all floating production systems (FPSs), variously described as column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc.* They also include facilities for product measurement and royalty determination (e.g., lease Automatic Custody Transfer Units, gas meters) of OCS production on installations not on the OCS. Any group of OCS installations interconnected with walkways, or any group of installations that includes a central or primary installation with processing equipment and one or more satellite or secondary installations is a single facility. The Regional Supervisor may decide that the complexity of the individual installations justifies their classification as separate facilities.

(2) As used in 30 CFR 550.303, means all installations or devices permanently or temporarily attached to the seabed. They include mobile offshore drilling units (MODUs), even while operating in the “tender assist” mode (*i.e.,* with skid-off drilling units) or other vessels engaged in drilling or down-hole operations. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to

emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc.* During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(3) As used in §250.490(b), means a vessel, a structure, or an artificial island used for drilling, well completion, well-workover, or production operations.

(4) As used in §§250.900 through 250.921, means all installations or devices permanently or temporarily attached to the seabed. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, *etc.* During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(5) As used in subpart S of this part, all types of structures permanently or temporarily attached to the seabed (e.g., mobile offshore drilling units (MODUs); floating production systems; floating production, storage and offloading facilities; tension-leg platforms; and spars) that are used for exploration, development, and production activities for oil, gas, or sulphur in the OCS. Facilities also include DOI regulated pipelines.