4. BEST AVAILABLE TECHNOLOGY [18 AAC 75.425(e)(4)]

This section discusses the best available technology (BAT) requirements in 18 AAC 75.425(e)(4)(A), (B), and (C) to address technologies not subject to response planning standards or performance standards in 18 AAC 75.445(k)(1) and (2). The discussion of each technology covers the requirement to analyze applicable technologies and to provide a justification that the Point Thomson technology is BAT. The spill prevention and response equipment for Point Thomson meets the BAT requirements because it meets the response planning standards and performance standards in 18 AAC 75.

4.1 COMMUNICATIONS [18 AAC 75.425(e)(4)(i)]

The BAT analysis of the communication systems for spill responses at Point Thomson is described in the ACS *Technical Manual, Volume 1*.

ACS Tactic L-11A

4.2 SOURCE CONTROL [18 AAC 75.425(e)(4)(A)(i)]

4.2.1 Well Source Control

ExxonMobil believes surface intervention constitutes BAT for source control of a blowout (see Table 4-1). This technology supplements the existing well source control BAT through the addition of voluntary well ignition in the event of an unrestricted blowout. Voluntary ignition for the Point Thomson gas condensate field will provide an effective means of discharge control of liquid hydrocarbons to the environment without violating air quality standards and will create a safer working environment for subsequent surface intervention operations to secure the well.

Surface intervention and relief well drilling will be two methods used to regain control of a well blowout after the primary (mud weight) and secondary (BOPE) barriers have been breached. Surface intervention includes reestablishing the primary barrier (circulating or bullheading fluids or a dynamic kill) and/or installing or repairing the secondary barrier (by well capping or by restoring the integrity of existing BOPE).

The severity of the well control event dictates the surface intervention response. In the event of a minor flow, control methods could be as simple as sealing a leak or repairing an equipment component, and voluntary well ignition would not be necessary. In the event of substantial flow, voluntary ignition will be used for immediate source control and appropriate surface intervention methods would follow. Blowout ignition as planned here is a source control technique for spill prevention purposes rather than a means of cleaning up the oil after it has reached the surface.

Relative to its alternatives, well ignition is expected to yield net environmental benefits, particularly where blowout condensate would otherwise enter open water. Igniting a blowout will minimize the amount of condensate that reaches the ground or water surface. The combusted condensate aerial plume will not contaminate the surface as an oil spill. Under the conditions of a blowout at Point Thomson, the smoke, including combustion gases and soot particulates, is expected to have no effects on public health or wildlife (see the public health effects in the Alaska Regional Response Team's "*In Situ* Burning Guidelines for Alaska" in the *Federal/State/Tribal Unified Plan for Alaska*).

TABLE 4-1
BEST AVAILABLE TECHNOLOGY ANALYSIS
WELL BLOWOUT SOURCE CONTROL

BAT EVALUATION CRITERIA	EXISTING METHOD: SURFACE INTERVENTION TOOL KIT INCLUDING WELL IGNITION	ALTERNATE METHOD: RELIEF WELL DRILLING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Surface intervention is in use globally. Surface intervention, well ignition, and well control equipment fit for this purpose is located on the North Slope and at Point Thomson. Additional equipment can be on location within 24 to 48 hours.	Relief well drilling equipment (rigs, down hole tools, etc.) is available though not widely used. If two rigs are used at Point Thomson, one will serve as the relief rig for the other. If only one rig is used at Point Thomson, an agreement will be arranged with other operators for a relief well rig. Mobilization time could be substantial depending on time of year.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Equipment is currently available on the North Slope, at Point Thomson, or on retainer via contract. Experienced well control specialists familiar with the technology and techniques are under contract to ExxonMobil.	Relief well drilling technology is mature. The tools and techniques have been perfected over time. ExxonMobil has experience in their application.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Excluding blowouts which stop flowing through natural causes (bridging, depletion, etc.), surface intervention is clearly effective since the technique is responsible for controlling most of the remaining blowouts (see description below in this section). When surface intervention is supplemented with voluntary well ignition the spill volumes and environmental impact are minimized. Voluntary ignition as a discharge control method is extremely effective when the well fluid is highly combustible such as a gas condensate.	Successful relief well drilling for blowout control has been thoroughly documented in the industry; however, this technique has only controlled the flow in 4 percent of all blowouts (see description below in this section). Although a relief well is effective, it is the longest duration source control and pollution mitigation measure because new locations must be prepared, rigs mobilized, and the relief well drilled to intersect the original blowout well.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Equipment fit for this purpose is already owned and/or under long-term contract. Surface intervention requires the maintenance of open-end contracts with trained specialists to implement well control/capping operations. Voluntary ignition of blowout fluids will significantly reduce cleanup costs. The cost for 15 days for surface intervention efforts is substantially less than the cost for relief well drilling.	Time and cost of permitting, on-site construction, well planning and executing relief wells is estimated to be at least an order of magnitude larger than the cost of surface intervention.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Surface intervention is established technology which has been improved since its frequent application during the Iraq-Kuwait conflict in early the 1990s.	Relief well drilling technology is similar to current methods used to drill/complete North Slope wells.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Technology is compatible and applied at surface (no sensitivity to well type).	Technology is compatible though potentially sensitive to blowout well types (ERD, remote locations, etc.). Relative wellbore-location uncertainty on high departure wells may result in problems intersecting the target wellbore.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible with all drilling operations. Applied at surface - no sensitivities to well type (ERD, remote locations, etc.). Prior proven success in onshore and offshore environments. Demonstrated high success rate in historical well control efforts.	Method feasibility contingent upon geographical access near area of blowout. Lack of year-round access to some locations (offshore Beaufort Sea) limits application. Very little evidence of successful application of relief well drilling as the primary mitigation measure of control. Relief wells may be preferred response method in some rarely occurring well control events.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	Technology provides the best-proven opportunity to quickly reduce environmental impacts. Voluntary ignition of the blowout well (if applied) will substantially reduce the spilled liquid volume. The duration is significantly less than conventional alternative technologies.	Technology provides additional exposure and environmental risks during application. Technology application may be seasonally limited, leading to durations of 36 to 180 days. Relief wells may require additional gravel placement and mobilization or demobilization affects on the local environment. Drilling a relief well is accompanied by the additional risk of a second well control event.

The authority to ignite a well blowout will be delegated to the Drilling Supervisor on the rigsite. It will be his responsibility to ensure the safety of personnel and to assess the situation.

The Drilling Supervisor will determine if voluntary ignition is necessary either from a safety or an environmental standpoint.

The rationale for acceptance of surface intervention as BAT is provided in the following discussion.

Surface Intervention

Over the past decade surface intervention techniques have been developed and proven to be both efficient and effective in regaining control of damaged wells and reducing the associated environmental impacts. Significant improvements in surface intervention techniques and procedures have been developed by a variety of well-control specialist companies around the world. Their use was instrumental in controlling the Kuwaiti fires and mitigating the associated environmental damage.

Surface intervention operations are highly dependent on the severity of the well control situation. ExxonMobil has fixed-wing aircraft to mobilize specialized personnel and all equipment (e.g., capping stack, cutting tools) to Point Thomson within 1 to 2 days after notification.

ExxonMobil has access to an inventory of fire-fighting equipment permanently warehoused on the North Slope. The equipment includes two 6,000-gpm fire pumps, associated piping, lighting, transfer pumps, Athey wagons, specialized nozzles, and fire monitor shelters listed in Table 1-7. Prior to drilling startup, a comprehensive list of required equipment, which includes equipment on the North Slope and elsewhere, will be prepared. This equipment represents a standard array of fire-fighting and well control equipment normally mobilized by well control specialists in a blowout event. Maintaining much of this equipment in-place on the North Slope significantly minimizes the time required to mobilize the required well control equipment in an actual blowout event. Other equipment for surface intervention operations will be on location at Point Thomson.

Surface intervention is both compatible and feasible with all drilling operations because the technology is applied at the surface. There are no sensitivities to well types (e.g., extended reach drilling, horizontal drilling) or location (e.g., remote, island). Surface intervention techniques have been applied both on land and at offshore locations to regain well control and have historically proven successful in regaining well control much faster than the more time-consuming alternative of drilling a relief well.

Drawing on a database of more than 1,000 blowouts from US Outer Continental Shelf (OCS) and onshore Texas wells, Skalle et al. (SPE 53974), report findings which indicate that surface intervention is generally more successful in rapidly regaining well control than drilling a relief well. If the roughly 5 percent of the wells that are missing data regarding the kill method are ignored, surface intervention was the kill method employed on 69 percent of all the remaining blowouts. Bridging/depletion and relief wells were the mechanisms in 27 and 4 percent of the well kills, respectively. If the data are restricted to only those wells in which either relief wells or surface intervention was the kill method, 95 percent of the wells were controlled by surface intervention and only 5 percent of the blowouts were controlled with relief wells. There can be no doubt that surface intervention techniques (BOPs, capping, mud, cement, and installation of equipment) are proven methods that are used in controlling the majority of well blowouts. Surface intervention is usually the preferred control method. Only in rare cases in which casing cannot be accessed by excavation or when entry to the wellbore is blocked will a relief well be required. However, our plan includes pursuing a relief well in conjunction with the surface intervention. It is worth noting that in Kuwait where surface wellhead equipment had been severely damaged by explosives, no relief wells were attempted or necessary.

ExxonMobil maintains an operating agreement with well control specialists who can assist in the intervention and resolution of well control emergencies. Maintaining an open contract with well control specialists is a minimal annual cost. Any additional services required during an actual response would be provided at previously agreed rates.

In a well blowout event, surface intervention operations would commence with ExxonMobil's activation of well control specialists and mobilization of key personnel and equipment. Dynamic and surface well control methods would continue to be attempted, if safe to do so. Once surface intervention is selected, safe re-entry to the wellhead area would be established and rig equipment moved to allow safe access. If the rig moving system were unavailable or inactive, then heavy bulldozers, block and tackle, and/or cranes would remove the rig from the wellhead area. Once safe access is regained, intervention operations would commence.

Data from MMS and SINTEF Civil and Environmental Engineering (Norway) indicate that surface intervention technologies provide the shortest duration and most effective option for regaining well control and minimizing environmental impacts once initial control measures have failed.

In summary, ExxonMobil believes surface intervention to be BAT because it is the most expedient and effective method for restoring well control, and that voluntary ignition in the case of a major blowout is the best means of discharge control to protect the environment and to create a safer working environment for the well control team.

Relief Well Drilling

Relief well drilling is an alternative method to surface intervention. Relief well drilling has historically been accepted as the blowout mitigation method that would be applied on the North Slope. Relief well drilling technology is compatible with North Slope drilling operations although it may be sensitive to both the well location and well types.

If two rigs are used at Point Thomson, one of the two rigs will function as the relief rig. Otherwise the rig will be transported from elsewhere in Alaska or Canada. Downhole and surface equipment (e.g., tubulars, wellheads) to support relief well drilling operations is available.

Although relief well drilling has often been proposed as a blowout response method, it has been attempted only once as a mitigation measure to control blowouts on the North Slope (i.e., ARCO Cirque blowout, 1992). In the 1992 Cirque case, well control was regained by a combination of surface intervention techniques with an assist from natural bridging before the relief well reached total depth.

Methods for drilling a relief well are similar to current methods used to drill and complete North Slope production wells today. Advances in directional drilling technology allow more precise wellbore placement and increase the likelihood of success of a relief well. Unfortunately, relief well attempts will be more sensitive to well locations and/or well types. For extended reach wells or remote locations with limited access, relief well drilling will be both challenging and time consuming, thereby adding to the overall environmental impact and volume spilled during a blowout.

Government and industry data (Scandpower Report 27.83.01) indicate that of the 117 total North Sea and Gulf of Mexico blowouts between 1980 and 1999, only four relief wells were drilled to regain control. For the 26 "deep" blowouts below surface casing during the same time period, no relief wells were needed or even attempted. In each of the "deep" blowouts, well control was regained through conventional surface intervention or by natural means (formation bridging).

Selecting an appropriate surface location is critical to relief well placement. If surface locations are not near the blowout location, the relief well can often pose significant challenges (e.g., tortuous directional drilling or extended reach drilling) to reaching the target formations in the blowout well. Optimally, a relief location will be positioned to minimize drilling time and complexity to reach target formation, to provide a suitable working surface to support drilling operations, and will be away from the blowout plume and associated explosion hazards. Optimum surface locations are rarely available on the North Slope, and therefore, relief well drilling is often the least desirable option. Fortunately at Point Thomson it may be possible to use existing locations from previous exploration wells.

Relief well drilling to a "deep" blowout below surface casing can be a time-consuming and costly process. If access to the blowout location is unavailable, alternative relief well locations must be found and/or constructed (e.g., access roads, gravel pads in the summer, ice pads in the winter). After permitting, site construction, well planning, and rig mobilization, the relief well must still be drilled. On the North Slope, the time needed to drill an onshore relief well is often estimated in the 36- to 90-day range. Drilling an offshore relief well could take significantly longer (up to 180 days) depending on the ice and water conditions and weather restrictions. These lengthy timelines add to the overall environmental impact (spill volume) of the blowout. Based on historical data (Scandpower Report 27.83.01), it is estimated that between 93 and 97 percent of blowouts would be under control by other means by the time the relief well drilling rig could be mobilized.

Relief well drilling success is dependent on access to an area near the blowout well and directional drilling techniques to ensure blowout well intersection. Lack of year-round road access and pad availability significantly impact estimated relief well timelines. Relief well planning will consider use of exploration pads.

Relief wells take the longest time of any alternative to effectively regain well control. In addition to the longer blowout duration, the relief well itself introduces additional environmental risks. Some old gravel pads will be retained for relief wells; however, if access to a site near the blowout well is limited, a new gravel or ice pad must be quickly constructed. If gravel is required there will be an impact to the tundra where gravel is placed. During equipment mobilization and relief well drilling operations, additional risks of spills and tundra impacts are posed. During the drilling of the relief well itself, the risk of a second well control event is introduced.

Conclusion

ExxonMobil maintains that surface intervention, supplemented by voluntary ignition when needed, constitutes BAT for well source control. Table 4-1 summarizes surface intervention as BAT for a blowout. Historical evidence clearly indicates that surface intervention has greater reliability and application for well control than relief well drilling. Surface intervention response times account for at least a 50 percent reduction in blowout durations when compared to those for relief well drilling.

4.2.2 Pipeline Source Control

Condensate Export Pipeline Source Control

Source control procedures for a spill from the condensate export pipeline, as required by 18 AAC 75.425(e)(1)(F)(i), involve the placement of automatic valves at CPF to stop the flow of liquids into the Point Thomson condensate export pipeline, and at the Badami tie-in.

There are two technology options for the automatic valves: actuated ball valves and actuated gate valves. Both valve options, when installed in new condition, are similar in terms of availability, transferability, cost, compatibility, and feasibility. In terms of effectiveness, ball valves typically have slightly faster closure times than gate valves. As required by 18 AAC 75.055(b), the flow of oil or product/gas can be completely stopped by these valves within one hour after a discharge has been detected. The valve closure time for these types of valves is usually 2 to 3 minutes. See Table 4-2 for BAT analysis for source control for the export pipeline.

Gathering Line Source Control

The high-pressure gathering lines, which will transport full wellstream production from the East and West Drilling Pads to the CPF, will each be connected to a manifold at their respective pads. The pipeline source control procedures for the gathering lines include the actuation of shutoff valves in each of the well production lines tying into the manifold. The valves on each well line will shut down wells and close production flowlines. Actuated valves will also be placed in the gathering lines at the CPF. Both sets of actuated valves will be provided to stop the flow of full wellstream gas and liquids into the gathering lines. Table 4-3 shows the BAT analysis for the gathering and well oil line source control.

4.2.3 Tank Source Control

Oil storage tank overflow control BAT analysis involves tank source control and tank liquid level determination. The BAT review for source control focuses on technology to stop the flow of product into the tank (Table 4-4). Source control procedures involve emergency shutdown valves on the fill line. Tank source control BAT for a ruptured tank is secondary containment or a double-wall tank, also shown on Table 4-4.

Automatic valves are provided on process and large storage tanks that may be subject to continuous filling or draining as part of the production process. Automatic valves are considered BAT for such tanks because they provide the most effective means to stop the flow of oil into tanks whose levels are constantly changing (Table 4-4). However, the facility operator will also have the ability to manually close tank valves if low or high level alarms indicate a potential problem. The valve type selected for this service is activated by a liquid-level detector (float switch or equivalent), and is the best available technology.

Manual valves will be used on regulated oil storage tanks that are filled infrequently. The tanks will be subject to fluid transfer procedures (Appendix A) for tank filling and will require the presence of an operator during filling operations. Tank spill root-cause analysis indicates that source control during filling of tanks is best achieved by the on-site presence of an operator who can immediately stop a tank-filling operation if a potential problem occurs. For this reason, manual valves are considered BAT for infrequently filled tanks (Table 4-4). Tanks will be equipped with a high-level alarm with local audible alarm to notify the Operator when a certain level of liquid in the tank is reached during tank filling operations.

TABLE 4-2
BEST AVAILABLE TECHNOLOGY ANALYSIS SOURCE CONTROL ON CONDENSATE EXPORT PIPELINE

BAT EVALUATION CRITERIA	PROPOSED METHOD: AUTOMATIC VALVES (BALL OR GATE)	ALTERNATE METHOD: CHECK VALVES	ALTERNATE METHOD: VERTICAL LOOPS
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology exists and is common in pipeline systems.	Technology exists and is common in pipeline systems.	Technology exists.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	This technology is transferable to this pipeline.	This technology is transferable to this pipeline.	This technology may be transferable to the pipeline to reduce spill volumes.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	An effective means of isolating pipeline system quickly.	Less effective means to reduce spillage where terrain profile limits oil drainage.	An effective means to reduce spill volumes by creating natural drainage breaks.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Approximately $200,000 per valve.	Approximately $50,000 per valve.	Possibly the same cost as automatic valves.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is current.	Method is current.	Application of existing technology to new use.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible with the pipeline system and sites selected based on reducing release volumes.	Compatible with the pipeline system.	Compatible with the pipeline system but have to be engineered to ensure expansion and forces are within acceptable limits.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible and is commonly used.	Is feasible to install.	Feasible to install but has not been proven. There are still some concerns over operational aspects.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	There is a possibility that leaks or drips could occur on the valves, but these can be minimized by proper maintenance for the valve.	There is a possibility that leaks or drips could occur on the valves. Check valves are a major source of pipeline leaks.	No additional impacts.

TABLE 4-3
BEST AVAILABLE TECHNOLOGY ANALYSIS
GATHERING AND WELL OIL LINE SOURCE CONTROL

BAT EVALUATION CRITERIA	PROPOSED METHOD: ACTUATED VALVES ON WELL FLOWLINES AND GATHERING LINES AT CPF	PROPOSED METHOD: MANUAL SHUTDOWN OF WELLS	ALTERNATE METHOD: ACTUATED VALVE ON GATHERING LINE ONLY
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology exists and is common in pipeline systems.	Technology exists and is common in pipeline systems.	Technology exists and is common in pipeline systems.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	This technology is transferable to the pipelines.	This technology is transferable to the pipelines.	This technology is transferable to the pipelines.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	An effective means of isolating pipeline systems quickly.	Less effective for rapid isolation of well and gathering lines.	Less effective for isolation of well and gathering lines.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Less than $500,000.	Less than $500,000.	Approximately $500,000 for a 16-inch corrosion resistant alloy rated to 10,000 psi.
AGE AND CONDITION: The age and condition of technology in use by the applicant	The valves would be new upon installation.	The valves would be new upon installation.	The valves would be new upon installation.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible with the pipeline system and sites selected based on reducing release volumes.	Compatible with the pipeline system.	Compatible with the pipeline system.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible.	Method is feasible.	Method is feasible.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	There is a possibility that leaks or drips could occur on the valves, but these can be minimized by proper maintenance and visual surveillance.	There is a possibility that leaks or drips could occur on the valves, but these can be minimized by proper maintenance and visual surveillance.	There is a possibility that leaks or drips could occur on the valves, but these can be minimized by proper maintenance and visual surveillance.

TABLE 4-4
BEST AVAILABLE TECHNOLOGY ANALYSIS TANK SOURCE CONTROL

BAT EVALUATION CRITERIA	PROPOSED METHOD: AUTOMATIC VALVE CLOSURE	PROPOSED METHOD: SECONDARY CONTAINMENT	PROPOSED METHOD FOR INFREQUENTLY FILLED TANKS: MANUAL VALVE CLOSURE
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology is available and it is commonly done in piping systems.	Technology is available and is commonly used. Interstitial space of double-wall tank construction and toed platform will provide secondary containment.	The oil transfer line for filling tank is manually operated with a check valve to prevent reverse flow.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Transferable.	Transferable.	Transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Additional automation would afford little benefit given the existing filling procedures and requirement for continuous on-site presence of operator during fill operation.	This technology has proven highly effective in minimizing the spread of spilled oil from a tank leak.	Because operators are required to remain at or near the tank during fill operation and an audible alarm is provided should the tank reach a high level, manual intervention is effective in source control.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Automation of this valve would cost \$15,000 to \$20,000 over the base case. ExxonMobil still requires the operator be at the fill site to oversee the fill operation.	This is the base case option.	This is the base case option.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is more complex and current.	The system is simple, well proven and current.	The system is simple, well proven and current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Method is compatible.	Method is compatible.	Method is compatible.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible.	Method is feasible.	Method is feasible.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	There are no offsetting environmental impacts.	There are no offsetting environmental impacts.	There are no offsetting environmental impacts.

NOTE: Tank fill valves close automatically on high level detection.

4.3 TRAJECTORY ANALYSES [18 AAC 75.425(e)(4)(A)(i)]

ACS Tactic L-11B

The BAT analysis for trajectory analyses and forecasts are described in the ACS *Technical Manual, Volume 1*.

4.4 WILDLIFE CAPTURE, TREATMENT, AND RELEASE PROGRAMS [18 AAC 75.425(e)(4)(A)(i)]

ACS Tactic L-11C

The BAT analysis for wildlife capture, treatment, and release programs are described in the ACS *Technical Manual, Volume 1*.

4.5 CATHODIC PROTECTION [18 AAC 75.425(e)(4)(A)(ii)]

Point Thomson oil storage tanks will be on elevated platforms and will not require cathodic protection. Regulation 18 AAC 75.445(k)(2) states that technology demonstrated to be in compliance with the performance standards in 18 AAC 75.005 through 18 AAC 75.080 are determined to be equivalent to BAT. The requirement for a BAT analysis is provided in 18 AAC 75.425(e)(4)(A)(ii) for cathodic protection or other approved corrosion protection control system if the system is required by 18 AAC 75.065(h)(3). However, that regulation requires corrosion control systems only for tank bottoms where soil conditions warrant. The Point Thomson tanks will not be in contact with soil, and consequently will not be subject to corrosion control system requirements. As such, no BAT analysis for a tank cathodic protection systems is necessary.

4.6 LEAK DETECTION SYSTEMS FOR TANKS [18 AAC 75.425(e)(4)(ii)]

The leak detection for the diesel tanks will be a sump on the tank double wall with an alarm level transmitter. In the event of a leak in the inner tank wall of the tank, diesel will flow through a 1-inch ball valve and sight flow glass, and into a 6-inch pipe. This pipe will act as a sump to collect leaked liquids. A level transmitter on the sump will trigger an alarm in the control room. A manual valved connection to the sump will provide for cleanout. The system has been selected due to its higher degree of sensitivity to leaks. The tank leak detection BAT review is provided in Table 4-5.

4.7 LEAK DETECTION FOR CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.425(e)(4)(A)(iv)]

The BAT analysis for the condensate export pipeline leak detection system addresses the following alternative technologies:

- Mass-Balance Line Pack Compensation (MBLPC)
- Visual surveillance
- Statistical Analysis of Pipeline Operating Conditions (SAPOC)
- Mass Balance (MB)
- Real-Time Transient Model (RTTM)

The rationale in determining the most appropriate leak detection system or systems for the Point Thomson condensate export pipeline will be based on operational philosophy, in addition to criteria stipulated in the BAT analysis. First, there must be redundancy (i.e., reliance not placed on a single leak detection system). Secondly, the technology should be state-of-the-art and capable of immediately detecting a sudden large-volume loss of product

TABLE 4-5
BEST AVAILABLE TECHNOLOGY ANALYSIS
TANK LEAK DETECTION

BAT EVALUATION CRITERIA	PROPOSED METHOD: EXTERNAL SUMP WITH ALARM LEVEL SWITCH	PROPOSED METHOD: FLOAT OPERATED EXTERNAL CAGE LEVEL SWITCH	ALTERNATE METHOD: ANNULAR SPACE DETECTION
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	A collection basin or sump is standard practice in the oil and most other industries.	Method is available and used by double-wall tank manufacturers.	This method could be used as an alternate or a backup to the sump level switch system.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Method is transferable.	Method is transferable.	Method is transferable.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	This method provides a means of rapidly identifying any leak and sounding an alarm to Operations.	This method provides a means of rapidly identifying any leak and annunciating an alarm to Operations.	This method would provide adequate leak detection, however, a larger spill would have to occur before it could be detected and annunciated to Operations.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Cost is minimal.	Cost is minimal.	Cost is minimal.
AGE AND CONDITION: The age and condition of the technology in use by the applicant	Method is proven technology that has been used for many years.	Method is proven technology.	Method is proven technology used by double-wall tank manufacturers.
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant	Method is compatible.	Method is compatible.	Method is compatible.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Detects a leak based on a rising level.	Detects a leak based on a rising level.	Detects a leak based on a rising level.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits	Standard practice, simple, few moving parts, no maintenance.	Standard practice, simple, no maintenance.	Simple, no moving parts, no maintenance.

as well as detecting a low threshold chronic (pinhole) leak. Thirdly, the system should be commercially available, in use on similar pipeline systems, and available from a vendor with a proven track record. See Table 4-6 for BAT analysis of leak detection for the export pipeline.

Each leak detection system has strengths and weaknesses that depend on the specific pipeline operating characteristics. The type of system selected depends on the combination of several technologies, including flow measurement, instrumentation, communications, and computer hardware and software. Additional considerations include experience operating a system under similar circumstances (e.g., similar pipeline flow conditions) and compatibility with existing systems in the same pipeline network.

Although a specific vendor of the leak detection system has not been selected, our current analysis of the leak detection technology indicates that capabilities equivalent to those previously identified as BAT for similar pipelines can be achieved for the Point Thomson condensate export pipeline.

Mass Balance Line Pack Compensation

The MBLPC system provides a very accurate method of detecting smaller leaks over a longer period of time or larger leaks over a short period of time. Operational experience at other North Slope oil fields using the MBLPC system has verified that it provides the most reliable and accurate method of pipeline leak detection.

The MBLPC system works by continuously measuring the amount of condensate entering and leaving the pipeline. The system relies on accumulating the differences between the inflow and outflow meters. The higher the meter accuracy, the faster and more sensitively the MBLPC system can perform. Pipeline flow data are presented to the leak detection computer in timed data sets that are aggregated over longer time segments referred to as accumulators. Pressure is also accurately measured using pressure transmitters. The computer calculates the corrected volume of oil entering and leaving the pipeline system. Typically, discrepancies are calculated between these values and compared on a time-segment (accumulator) basis. Based on past operating experience, a leak detection threshold of 1 percent of daily throughput can be expected for the MBLPC system.

Visual Surveillance

Visual surveillance provides a supplement to on-line leak detection systems and has been used on the North Slope as well as other areas of the United States. Visual surveillance can validate alarms generated by the on-line system, as well as aid in the detection of small leaks that may be below the threshold limit of the system. It is simple to implement as part of general daily operations and does not involve up-front costs.

Statistical Analysis of Pipeline Operating Conditions

The SAPOC uses pressure transducers located at the CPF and Badami pipeline tie-in. Pressure readings are recorded, stored, and analyzed within the leak detection system software. When pressure records are identified by the software to be outside an acceptable range, the leak detection system generates an alarm. The level of analysis, the number of stored variables, and the modeling algorithm provide for some capability of leak detection in flow with pressure transients. Additionally, SAPOC has the capability of locating a leak through analysis of the pressure data.

TABLE 4-6
BEST AVAILABLE TECHNOLOGY ANALYSIS
LEAK DETECTION FOR CONDENSATE EXPORT PIPELINE

BAT EVALUATION CRITERIA	PROPOSED METHOD: MASS BALANCE LINE PACK COMPENSATION (MBLPC)	PROPOSED METHOD: VISUAL SURVEILLANCE	PROPOSED METHOD: STATISTICAL ANALYSIS OF PIPELINE OPERATING CONDITIONS (SAPOC)	ALTERNATE SYSTEM: MASS BALANCE (MB)	ALTERNATE SYSTEM: REAL TIME TRANSIENT MODEL (RTTM)
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	MBLPC is widely used on condensate pipelines and is commercially available.	Technology is available.	SAPOC is widely used on condensate pipelines and is commercially available.	MB has been widely used on condensate pipelines. It performs best under steady-state conditions. However, vendors are now recommending MBLPC over MB because MBLPC offers better performance than MB.	RTTM is used in condensate pipelines. However it is best suited for transient flow conditions.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	MBLPC is used on condensate pipelines. It performs best if: 1. Transient flow conditions do not occur frequently. 2. There is no multi-phase flow. 3. There is no slack-line flow.	Can be used.	SAPOC technology is used on condensate pipelines. It performs when: 1. Transient flow conditions do not occur frequently. 2. There is no multi-phase flow. 3. There is no slack-line flow.	MB technology is widely used on condensate pipelines. It performs best if: 1. The condensate pipeline operates in a steady-state mode. 2. There is no batching. 3. There is no multi-phase flow. 4. There is no slack-line flow. 5. Temperature remains constant. 6. Pipeline is relatively short (on the order of 20 miles long).	RTTM is applicable to condensate pipelines. However, it is more appropriate for multi-phase flow conditions, transient flow conditions, and pipeline networks.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Can detect leaks that are as low as 1 percent of daily condensate throughput. MBLPC system performance is dependent upon the accuracy of condensate pipeline flow meters.	An effective means of identifying a leak that can be visually detected. Sometimes leaks occur that are below the threshold limit of the leak detection system and are spotted by visual detection. Must be used in conjunction with an automated leak detection system.	Can detect leaks that are as low as 1 percent of daily throughput. The system's performance is somewhat dependent on upon pump or compressor performance.	This method is less effective than MBLPC.	Can detect leaks that are 1 percent of the daily throughput even when the flow is transient.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	Less than $350,000.	The cost is based on the number of trips to cover the pipeline right-of-way. No up-front investment.	Less than $350,000.	Approximate cost is $50,000. It is the least expensive system to install.	Approximate cost is $350,000. RTTM is the most expensive system to implement and maintain.
AGE AND CONDITION: The age and condition of technology in use by the applicant	The required software and hardware will be new when installed.	Method is current.	The required software and hardware will be new when installed.	The required software and hardware would be new when installed.	The required software and hardware will be new when installed.

TABLE 4-6 (CONTINUED)
BEST AVAILABLE TECHNOLOGY ANALYSIS
LEAK DETECTION FOR CONDENSATE EXPORT PIPELINE

BAT EVALUATION CRITERIA	PROPOSED METHOD: MASS BALANCE LINE PACK COMPENSATION (MBLPC)	PROPOSED METHOD: VISUAL SURVEILLANCE	PROPOSED METHOD: STATISTICAL ANALYSIS OF PIPELINE OPERATING CONDITIONS (SAPOC)	ALTERNATE SYSTEM: MASS BALANCE (MB)	ALTERNATE SYSTEM: REAL TIME TRANSIENT MODEL (RTTM)
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	MBLPC is compatible with SCADA and is combined with Statistical Analysis of Pipeline Operating Conditions.	Method is compatible with all leak detection systems.	SAPOC is compatible with SCADA.	MB is compatible with SCADA.	RTTM is compatible with SCADA.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	MBLPC is routinely used on relatively short pipelines (on the order of 20 miles long).	Method is not feasible to continuously monitor the entire pipeline. Is useful as supplement to an on-line leak detection system.	SAPOC is a state-of-the-art proven technology.	MB is simple to implement on relatively short (approximately 20 miles) pipelines.	RTTM is a relatively complex and costly system to implement on condensate pipelines. It requires system calibration to tune detection accuracy and additional data measurements to calculate system response. Operators need higher level training to provide reliable operation.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	None, the system is preventive in nature. Implementation will significantly reduce oil loss to the environment if a leak were ever to occur.	None.	This system provides the assurance of reliable leak detection. Implementation will significantly reduce condensate loss to the environment if a leak were ever to occur.	MB is an effective leak detection system. Implementation will significantly reduce oil loss to the environment if a leak were ever to occur.	None, the system is preventive in nature. Implementation will significantly reduce oil loss to the environment if a leak were to occur.

Real Time Transient Modeling

The most sensitive, but also the most complex and costly leak detection method in use is RTTM. RTTM involves the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling. Conservation of momentum calculations, conservation of energy calculations, and numerous flow equations are typically used by the RTTM system. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions. This analysis is done in a three-step process. First, the pressure-flow profile of the pipeline is calculated based on measurements at the pipeline or segment inlet. Second, the pressure-flow profile is calculated based on measurements at the outlet. Third, the two profiles are overlapped and the location of the leak is identified as the point where these two profiles intersect. If the measured characteristics deviate from the computer prediction, the RTTM system sends an alarm to the pipeline controller. The more instruments that are accurately transmitting data into the model, the higher the accuracy of, and confidence in the model. Note that models rely on properly operating and calibrated instruments for optimum performance. Calibration errors can result in false alarms or missed leaks, and the loss of a critical instrument could require system shutdown.

The advantage RTTM provides over other methods is its ability to model all of the dynamic fluid characteristics (flow, pressure, temperature) and take into account the extensive configuration of physical pipeline characteristics (length, diameter, thickness, etc.), as well as product characteristics (density, viscosity, etc.). Additionally, the model can be tuned to distinguish between instrument errors, normal transients, and leaks. The distinct disadvantages of this system are the costs associated with implementing RTTM and the complexity of the system, which requires numerous instruments and extensive controller training and system maintenance.

Conclusion

The conclusion arising from the BAT review is that a combination of the MBLPC and visual surveillance systems is most appropriate for the Point Thomson condensate pipeline. The SAPOC will serve as a redundant system to the MBLPC and visual surveillance systems. The combination of these leak detection systems provides the ability to rapidly detect large and small volume leaks.

4.8 LIQUID LEVEL DETERMINATION [18 AAC 75.425(e)(4)(A)(ii)]

The liquid level transmitters for the ADEC-regulated tanks use state-of-the-art technology. Redundant electronic level transmitters mounted on the tank sense liquid level through a radar-type level transmitter. The transmitters sense a liquid level by measuring the distance from the top of the tank to the vapor/liquid interface. One transmitter signals the PCS, which controls tank level while displaying and alarming level readings in the control room. The secondary level gauge is for safety and signals the safety system. The safety system provides a backup level indication, alarms, and shutdown of equipment, and isolates the unit. Isolation valves are electrically and pneumatically opened and spring-closed, thereby ensuring positive action and isolation upon failure of either pneumatic or electrical power, even under extreme low-temperature conditions (Table 4-7A).

The controller for the storage and dispensing control system is modern state-of-the-art PCS. A safety instrumented system (SIS) ensures total reliability. The SIS has its own dedicated level gauge and shutdown valve and operates independently from the PCS. The SIS takes

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TABLE 4-7A
BEST AVAILABLE TECHNOLOGY
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	PROPOSED METHOD: RADAR CONTINUOUS LEVEL	PROPOSED METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: ULTRASONIC LEVEL SWITCH, CAPACITANCE LEVEL SWITCH, OR FLOAT LEVEL SWITCH WITH HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Radar technology is used in similar applications. It is being used on tanks for level determination. It is non-contact and not pressure, temperature or density dependent.	Microprocessor-based controllers are used in almost all electronic control systems in industry today. The reason for the popularity of controllers is that the controllers have proven to be BAT over the past 20+ years.	Hardware relay logic control systems are still in use today, but are becoming less popular. Ultrasonic point level switches are used in tanks throughout the world. Capacitance level switches are used in tanks throughout the world. Float level switches have been used throughout the world but are not as popular as they used to be since the use of ultrasonic and capacitance level switches.	Pneumatic control systems are used in very few applications today and never where pumps and motors are turned on or off.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Transferable to applicant operations. Tanks would be outfitted with a nozzle so instrumentation can be installed.	Emerson Delta V and all instrumentation are completely transferable to applicant's operations. Many facilities on the North Slope of Alaska use Allen Bradley PLCs or equivalent. The central plant control system will use Emerson Delta V for control and a TÜV (Technische Überwachungs Verein [a network of German certification agencies]) approved safety PLC for backup protection. The brands and models of instrumentation used in the control system design are also common to the central facility. Both Delta V or the backup safety PLC are equal to or better than an Allen Bradley PLCs. In combination, they give much greater control and reliability than a single Allen Bradley PLC.	Ultrasonic level switch is transferable to the Emerson Process Management Delta V process control system (PCS) and a TÜV approved safety PLC (e.g. ICS Triplex, Triconex, or HIMA triple redundant or redundant one out of two voting system). Capacitance level switch is transferable to Delta V for control with a TÜV approved PLC as a safety backup. Float level switch is transferable to the Allen Bradley PLC.	Transferable.

TABLE 4-7A (CONTINUED)
BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	PROPOSED METHOD: RADAR CONTINUOUS LEVEL	PROPOSED METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: ULTRASONIC LEVEL SWITCH, CAPACITANCE LEVEL SWITCH, OR FLOAT LEVEL SWITCH WITH HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Continuous level is non-contact and not pressure, temperature or density dependent. Can be affected by mist, steam, foam or turbulence.	Critical operation parameters such as tank levels are continuously monitored by both the control system and the safety system PLC and are displayed for easy operator reference. Any abnormal condition (i.e., high tank level) activates automatic safeguards (i.e., close tank inlet valves) to prevent spills, etc. Pre-alarms alert operators of pending abnormal conditions. The entire control system is designed to be fail safe. All field sensing devices, PLC hardware and software, and field-actuating devices are designed to stop diesel/methanol flow in the event any device fails. Dispensing pump incorporates an emergency shutdown valve (ESV) that closes under impact or fire exposure.	Relay systems do not provide for logic status monitoring or alarming. This method provides an easy means of identifying exactly when the level switch will activate. Repeatability is within 1/16 inch and this method has no moving parts. Capacitance level switch method would be a reliable means of detecting a high level, however it requires a minimum of 2 inches of probe above and below the liquid level. Also, if the dielectric of liquid changes, the point of switching would change. Float level switch method would provide adequate level sensing. However, float levels have been known to stick in certain applications.	Pneumatic systems are prone to freezing if moisture build-up occurs in the tubing.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Could require an additional instrument connection on the vessel, as well as routing of power for the unit. The cost could be in excess of $50,000.	All instruments and control system hardware were purchased to be fit for purpose, technically acceptable, and reasonably priced based on budgetary pricing. All instrument and controls technology used in the system design should remain in service for at least the next 20 years. Design changes can be implemented at minimal costs.	Cost is minimal.	The cost of design changes to a pneumatic logic system is high. Re-tubing is required for revision.
AGE AND CONDITION: The age and condition of the technology in use by the applicant	The required software and hardware would be new when installed.	All instrument and controls equipment is brand new, purchased specifically for this project.	The required software and hardware would be new when installed. Float level switch is an older technology.	The required software and hardware would be new when installed.

TABLE 4-7A (CONTINUED)
BEST AVAILABLE TECHNOLOGY ANALYSIS
STATIONARY STORAGE TANK LIQUID LEVEL DETERMINATION

BAT EVALUATION CRITERIA	PROPOSED METHOD: RADAR CONTINUOUS LEVEL	PROPOSED METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: ULTRASONIC LEVEL SWITCH, CAPACITANCE LEVEL SWITCH, OR FLOAT LEVEL SWITCH WITH HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
COMPATIBILITY: Whether each technology is compatible with existing operations and technology in use by the applicant	This technology is compatible with existing operations and technologies.	Allen Bradley PLCs are used at various facilities on the North Slope of Alaska. The central control system will use both Delta V or the backup safety PLC are equal to or better than an Allen Bradley PLCs. In combination, they give much greater control and reliability than a single Allen Bradley PLC.	Method is compatible.	Method is compatible.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Would require modifications to the vessel that would incur additional cost without any substantial increase in availability/reliability.	Allen Bradley PLCs or equivalent are easily programmed, commissioned, and maintained because of their software-based systems. All programming is compliant with International Electrotechnical Commission (IEC) 1131-3. System status, input/output status, and program status alarms are readily available to operating and maintenance personnel for troubleshooting. All PLC information is available for displaying on computers for quick and accurate operating responses to abnormal conditions.	Engineering revisions to relay logic systems are very time-consuming and costly. Maintenance is very low-tech and often causes more spurious trips than it prevents. Operator interface is available locally only.	Engineering revisions to pneumatic control systems are very time-consuming and costly. Operator interface is available locally only.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution and energy requirements, offset any anticipated environmental benefits	No additional environmental impacts; unit requires external power.	Electrically and electro-pneumatically operated valves provide high reliability for shutting down the diesel flow while consuming minimal amounts of energy.	None.	None.

corrective action (e.g. shuts down the tank) should the PCS and/or the operators fail to adequately control tank level. The control and safety system have the following design features:

- They are the state-of-the-art systems used in logic control and alarming.
- They have replaced relay systems because of the ease of programming in software versus hardware and interconnected wiring. Components are standardized and are easily replaced using off-the-shelf items.
- Both the PCS and the SIS have on-line continuous diagnostics capable of detecting and reporting equipment faults and failures on a real-time basis. Both have built in redundancy of controller, I/O cards, and power supplies.
- Both the PCS and SIS hardware and software can be selected, configured, and programmed to be fail-safe by detecting hardware and software failures and taking the appropriate control or alarm action.
- The data resident in PCS and SIS controllers can be easily accessed by computers or information technology departments using standardized databases.

Both the PCS and SIS programming databases are password protected. Only authorized personnel have access to make logic or shutdown sequence changes.

Table 4-7B presents BAT analysis for liquid level determination on portable storage tanks. On portable and temporary tanks the electronic types of liquid level indicators, which typically employ ultrasonic or microwave frequency transducers, are not BAT. Small portable tanks that are mounted on motor vehicles are subject to vibrations and jolts from being transported on unimproved roads and from wind gusts. These conditions result in liquid level measurements that fluctuate constantly, particularly for the more sensitive devices such as microwave frequency.

Float-type devices are particularly prone to jamming under these conditions. While it is possible to tune associated controller outputs to mitigate the effects of vibration and jolts, such a state of tune would significantly decrease their accuracy and response times in terms of liquid level measurement and preclude their use as leak detection devices.

Small temporary tanks on gravel pads or rigs are subject to similar vibrations and jolts. Accordingly, the use of sensitive liquid level devices on small portable and temporary tanks results in liquid level measurement errors and frequent false alarms. Handling during loading, transportation, and unloading may also result in physical damage to the level determination device or electronic components.

In addition, should the liquid level indicating devices be used to control automatic shutoff valves or pump shutoff relays, unanticipated valve closures or pump shutdowns may occur, potentially resulting in a release of product. The inability of the devices to function accurately and reliably on small portable and temporary tanks, and the significant cost of custom construction, installation, and maintenance preclude their use.

Flow-test tank fluids are typically composed of oil, water, associated emulsions and suspended solids. The multiphase nature of these fluids adversely impacts the accuracy and reliability of a variety of level determination devices. For example, the accuracy of microwave frequency devices is compromised by variations in liquid dielectric constant and electrical conductivity. As a result, application in multiphase liquid contexts is contraindicated.

TABLE 4-7B
BEST AVAILABLE TECHNOLOGY ANALYSIS
PORTABLE STORAGE TANK LIQUID LEVEL DETERMINATION SYSTEM

BAT EVALUATION CRITERIA	PROPOSED METHOD: VISUAL OBSERVATION	ALTERNATE METHOD: MICROPROCESSOR-BASED ELECTRONIC CONTROL SYSTEM	ALTERNATE METHOD: HARD-WIRED RELAY LOGIC CONTROL SYSTEM	ALTERNATE METHOD: PNEUMATIC CONTROL SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Existing method.	Microprocessor-based programmable logic controllers (PLCs) are used in almost all electronic control systems in industry today. The reason for PLCs' popularity is that the controllers have proven to be BAT over the past 20+ years.	Hardwired relay logic control systems are still in use today but are becoming less popular.	Pneumatic control systems are used in very few applications today and never where pumps and motors are turned on or off.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Transferable.	Allen Bradley SLC5 PLCs and all instrumentation are not transferable to the drill rigs.	Transferable, but not practical.	Undetermined.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Highly effective with strict adherence to BMP and local procedure. Tank liquid levels will be determined from direct observation through the hatch using a flashlight, fuel strapping tape, etc.	Not effective in this application.	Not effective in this application. In addition, relay systems do not provide for logic status monitoring or alarming.	Not effective in this application. In addition, pneumatic systems are prone to freezing if moisture build-up occurs in the tubing.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant.	Not applicable.	The cost to redesign the rig and its associated storage tank would be high.	The cost of design changes to a relay based logic system is high. Re-wiring is required for any revision.	The cost of design changes to a pneumatic logic system is high. Re-tubing is required for any revision.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Procedures have been in place since 1993 for fuel transfer operations.	Current technology.	Current technology.	Current technology.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible and widely used. Requires no change.	Compatible but not used on portable tanks and tanks on rigs.	Compatible but not used on portable tanks and tanks on rigs.	Compatible but not used on portable tanks and tanks on rigs.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Feasible and preferred due to potential for electronic or pneumatic systems to experience damage from rough handling.	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.	Rig tanks are frequently moved over rough roads. Rough handling has the potential to affect the accuracy and/or operability of the system.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements offset any anticipated environmental benefits	None.	None.	None.	None.

Alternatively, ultrasonic devices require contact with the process fluid; solids build-up or emulsion adherence to the sensor results in decreased accuracy and the need for frequent maintenance. Float-type devices are also subject to greatly reduced accuracy and reliability resulting from the solids content. The solids may cause float sticking and jamming. In addition, extreme cold weather results in pulleys that may not roll freely or may freeze up altogether, or associated cable systems that become inflexible. Any one or more of these effects renders the device unreliable.

Manufacturers of electronic devices indicate that temperatures lower than -30°F compromise the reliability and response time of the electronic components of these devices. Comprehensive review of historical weather data for the subject North Slope locations indicate that extreme low temperatures range from -58°F to -85°F. Use of these devices in such extreme low temperatures is not recommended.

In summary, the application of liquid level determination devices (in addition to manual gauging and direct observation) to portable and temporary tanks in remote arctic environments is not desirable for the following reasons:

- Significant potential for physical damage or damage to associated electronic components as a result of loading, unloading, or transportation.
- Requirement for power source, i.e., a potential source of ignition.
- Need for frequent maintenance.
- Lack of warranty.
- Decreased accuracy.
- Decreased reliability.
- Significant cost (e.g., device, power, installation, maintenance, and replacement).

As a consequence of these considerations, ExxonMobil proposes to use current BMP (Appendix A) for transfer procedures and visual inspection as BAT for liquid level determination in portable and temporary tanks.

Visual tank-liquid-level inspection consists of:

- Two personnel present during transfer, maintaining constant line-of-sight and communication;
- One person pumps while the other person constantly monitors tank levels throughout transfer; and
- Positive means of shutting off transfer.

4.9 PROTECTIVE WRAPPING OR COATINGS FOR TANKS AND PIPELINES [18 AAC 75.425(e)(4)(A)(ii)]

4.9.1 Tank Corrosion Protective Coating

A BAT analysis has not been performed for tank protective wrappings and coatings since the storage tanks at Point Thomson will be above-grade and therefore will not require protective wrappings or coatings.

4.9.2 Pipeline Corrosion Protective Coating

The Point Thomson condensate export pipeline and the gathering lines will be maintained aboveground for their entire lengths, except at road crossings. At road crossings the pipelines will pass through larger diameter pipes (sometimes called casings) and will be electrically isolated from the casing and the road materials. The pipeline inside the casing will be maintained with spacers for stability.

As required by 18 AAC 75.080(b)(1)(A), below-grade pipelines are protected from external corrosion by an external coating (Table 4-8). The available technologies for this coating are:

- Dual-layer fusion-bonded epoxy (FBE) for corrosion and mechanical protection,
- Single layer of conventional FBE for corrosion protection,
- Paint, and
- Coal tar enamel.

Of the four technologies, dual-layer FBE is considered the best available technology based on the physical properties of each technology in relation to the physical environment of the Point Thomson pipelines (Table 4-8).

Both dual-layer and single-layer FBE coatings are ductile. Dual-layer FBE, composed of an inner layer of conventional FBE for corrosion protection and an outer layer of impact-resistant FBE for mechanical protection, are more durable than a single-layer FBE coating. The inner layer of the dual-layer FBE coatings is the conventional FBE material that has been effective as a corrosion protection coating. Both layers, which are feasible to apply, have a low coating-breakdown factor causing less impact to the environment while making the dual-layer FBE coating compatible with sacrificial anodes. High coating-breakdown factors adversely affect sacrificial anode systems. The cost to apply the dual-layer FBE coating in a new condition is considered reasonable.

The Point Thomson condensate export pipeline will be carbon steel and will be coated with FBE at road crossings. The gathering lines will be constructed of Duplex stainless steel and will not be externally coated for corrosion protection. They will be covered with a coating of polyurethane foam for insulation purposes for their entire lengths.

4.10 CATHODIC PROTECTION FOR TANKS AND PIPELINES [18 AAC 75.425(e)(4)(A)(ii)]

4.10.1 Tanks

A BAT analysis has not been performed for tank cathodic protection since the storage tanks at Point Thomson will be above-grade and therefore will not require cathodic protection.

4.10.2 Pipelines

A BAT analysis has not been performed for pipeline cathodic protection since below-grade pipelines will be FBE-coated and cased, and will not be in direct contact with soil. Therefore, pipelines will not require cathodic protection.

TABLE 4-8
BEST AVAILABLE TECHNOLOGY ANALYSIS
EXTERNAL COATINGS FOR BELOW GRADE SECTIONS OF PIPELINE

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BAT EVALUATION CRITERIA	PROPOSED METHOD: FUSION BONDED EPOXY	ALTERNATE METHOD: COAL TAR OR EXTRUDED POLYETHYLENES	ALTERNATE METHOD: PAINTS (ENAMEL OR ZINC OXIDE PRIMER)	ALTERNATE METHOD: NO COATING
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	Technology is available and is used.	Technology is available and is used. Not available in existing coating mills in Alaska.	Technology is available and is used for aboveground piping.	Technology is available.
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Can be used.	Can be used.	Can be used.	Can be used.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	Effective means to provide coverage.	Would likely not be as effective as FBE. Likely to be damaged in shipment to the site at low temperatures and is not reliable within the pipeline operating temperatures.	Does not provide the protection that is required for below-grade pipe that comes in contact with soils.	Not effective means of providing protection of the below-grade sections of the pipeline. Also DOT regulations require that new pipelines have external coating.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology in use by the applicant	Comparable to other coating alternatives.	Comparable to other coating alternatives.	Comparable to other coating alternatives.	There would be no cost.
AGE AND CONDITION: The age and condition of technology in use by the applicant	Method is current.	Method is current.	Method is current.	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	Compatible with coating systems and installation method proposed.	Not compatible with cold temperature environment that the pipe will be installed in.	Not compatible with pipe that comes in contact with soils.	Compatible.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	Method is feasible and is commonly used.	Not feasible to use because it will not provide the level of protection required based on the operating temperature of the pipeline.	Not appropriate coating for a below-grade pipeline.	Not feasible to have uncoated below-grade pipe. DOT regulations require that new lines have external corrosion coating.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	No additional environmental impacts.	Coal tar coatings present possible environmental concerns when coating has to be removed for maintenance or field installation.	No additional environmental impacts.	No additional environmental impacts.

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