2. PREVENTION PLAN
[18 AAC 75.425(e)(2)]

2.1 PREVENTION, INSPECTION, AND MAINTENANCE PROGRAMS [18 AAC 75.425(e)(2)(A)]

2.1.1 Prevention Training Programs [18 AAC 75.007(d)]

ExxonMobil personnel at Point Thomson will receive training in a variety of areas, including general North Slope procedures, spill prevention, environmental awareness, job-specific safety training, and site-specific orientation. Through the initial and annual training detailed below, personnel will receive training in oil spill notification protocols, oil spill source control, and Hazardous Waste Operations and Emergency Response (HAZWOPER). The distribution and use of the *Alaska Safety Handbook, ExxonMobil Production Safety Manual,* and, the *North Slope Environmental Field Handbook* will further supplement the routine training program.

The North Slope Training Cooperative (NSTC) program is a 1-day training seminar that is mandatory for everyone who works in the North Slope oil fields. It consists of a series of training videos and lectures covering the following topics:

- *Alaska Safety Handbook* and *ExxonMobil Production Safety Manual,*
- Camps and Facilities Safety Orientation,
- Environmental Excellence,
- Hazard Communication (HAZCOM),
- HAZWOPER Awareness,
- Personal Protective Equipment (PPE), and
- Hydrogen Sulfide.

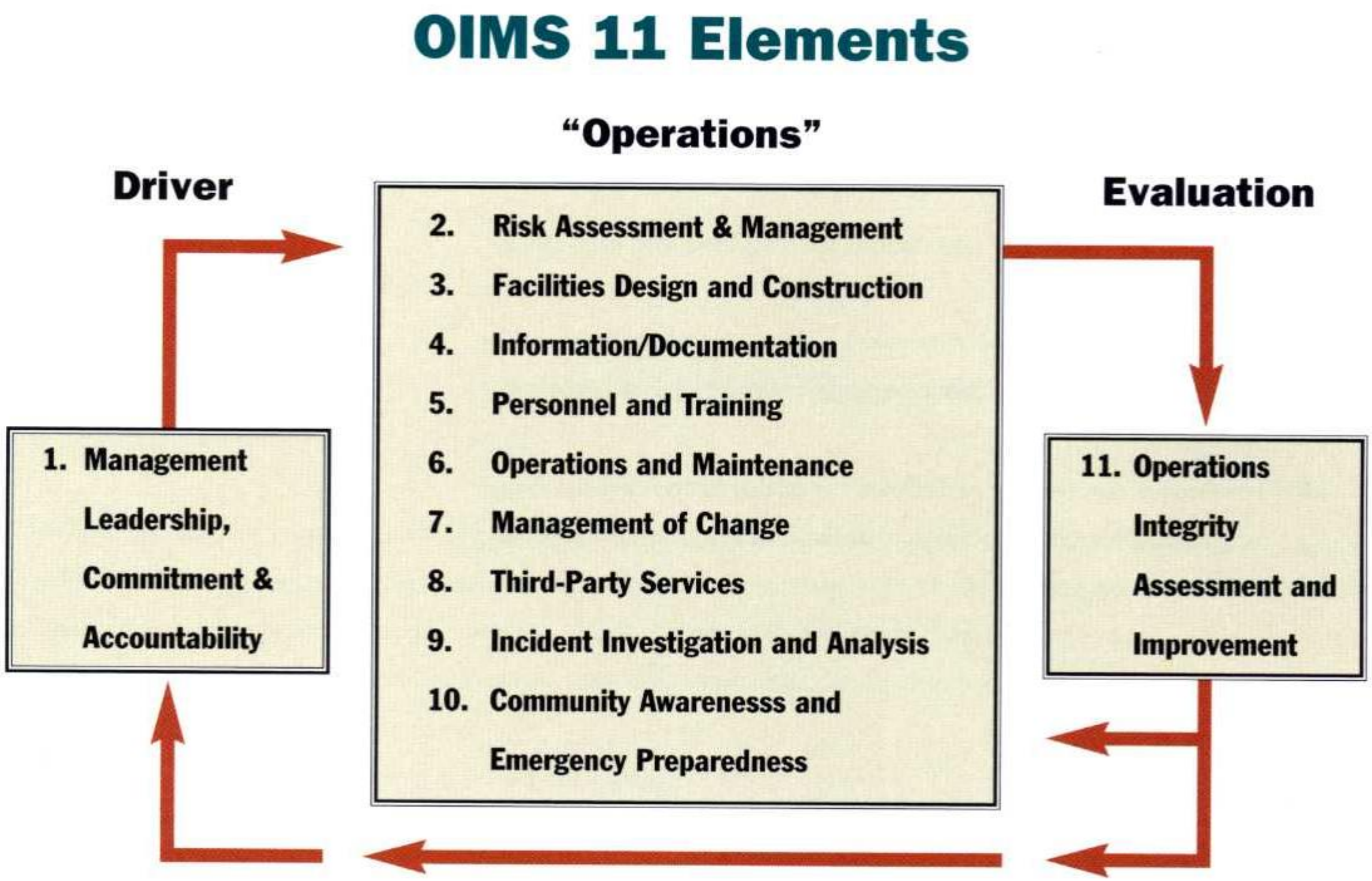
The NSTC program includes a review of the *North Slope Environmental Field Handbook*, which is made available to everyone working in the North Slope oil fields. The handbook provides a general overview of state and federal environmental regulations and programs applicable to the North Slope oil fields. It summarizes procedures developed by North Slope operators to comply with state and federal environmental regulations. The handbook covers programs specific to air, land, water, wildlife, spills, and waste management. It is supplemented with a site-specific safety manual issued by ExxonMobil.

Upon arrival at the facility, personnel will be provided a site orientation that includes familiarization with the Point Thomson emergency response and evacuation plans.

Point Thomson facility and response staff will also receive training in ExxonMobil Environmental Management Plan awareness and refreshers on fire extinguishers and HAZCOM, as required. Point Thomson facility and response staff which are qualified as pipeline operators under 49 CFR 195 Subpart G will also receive annual training according to the US DOT requirements listed in 49 CFR 195.403. Oil-handling staff receive training and an annual briefing in spill prevention topics.

Point Thomson will use the Operations Integrity Management System (OIMS) to ensure continuous improvement in environmental performance. The OIMS framework consists of 11 elements, as shown in Figure 2-1. The system uses direct input from technical specialists and field personnel, along with information developed through routine loss control and incident investigations, to minimize the potential recurrence of events. ExxonMobil developed OIMS to

FIGURE 2-1
OPERATIONS INTEGRITY MANAGEMENT SYSTEM ELEMENTS



manage safety, health and environmental risks. Elements of the system cover risk assessment and management, personnel training, incident investigation and analysis, and emergency preparedness. A specific Safety Management Plan in OIMS covers safety and occupational health.

Safety and environmental communications and bulletins will be regularly distributed to ensure that specific safety and environmental issues are properly communicated to all personnel. Field personnel will receive electronic and hard copies of these communications. In addition, most supervisors will discuss the communications and bulletins with their crew during safety meetings.

Waste management training (known as "Red Book" training) will familiarize Point Thomson facility personnel with the regulatory classification and disposal requirements for industrial wastes. The training covers classification of wastes, transportation requirements, and a description of each waste disposal facility on the North Slope. The course is mandatory for personnel who sign waste manifests as a generator, transporter, or receiver of waste.

Service company employees will receive instruction to promote safe conduct on the job, including a briefing by responsible supervisors prior to project commencement. Upon arrival in the operating areas, personnel will be instructed in safety and health responsibilities, including rules, procedures, injury reporting, and PPE. Employees will receive copies of and be briefed on the *Alaska Safety Handbook* and *ExxonMobil Production Safety Manual.*

Training records for ExxonMobil Point Thomson employees will be available through the employee's immediate supervisor or by contacting ExxonMobil's Anchorage office. Contractors will maintain their own training records. These records will be reviewed annually by ExxonMobil.

The training programs and operational procedures will serve to provide assurance that the likelihood of future spills caused by operator error or procedural deficiencies will be mitigated to the fullest extent.

2.1.2 Substance Abuse Programs [18 AAC 75.007(e)]

ExxonMobil complies with regulations promulgated by the US DOT under 49 CFR 40 that mandate biological testing and supervisory training programs. Point Thomson employees who fall under these regulations (i.e., employees involved in operation, maintenance, and emergency response positions in natural gas, liquefied natural gas, and hazardous liquid pipeline operations) will be required to undergo biological testing for reasonable cause following reportable accidents, alcohol or drug rehabilitation, and on a random basis. Other employees will fall under the Company's drug testing program. Each of these groups will be tested at a rate of 25 percent per year. Contract personnel will maintain their own records.

ExxonMobil is committed to a safe, healthy, and productive workplace for all employees. ExxonMobil recognizes that alcohol, drug, or other substance abuse by employees will impair their ability to perform properly and will have serious adverse effects on the safety, efficiency and productivity of other employees and ExxonMobil as a whole. The misuse of legitimate drugs, or the use, possession, distribution, or sale of illicit or non-prescribed controlled drugs on Company business or premises is strictly prohibited and constitutes serious misconduct, which will likely result in termination of employment. Possession, use, distribution, or sale of alcoholic beverages on Company premises is not allowed. Being unfit for work because of use of drugs or alcohol is strictly prohibited and constitutes serious misconduct, which will likely result in termination of employment. While this policy refers specifically to alcohol and drugs, it is also intended to apply to use of inhalants and other forms of substance abuse.

ExxonMobil recognizes alcohol or drug dependency as a treatable condition. Employees at Point Thomson who suspect they have an alcohol or drug dependency will be encouraged to seek advice and to follow appropriate treatment promptly before it results in job performance problems. The Employee Health Advisory Program or medical professional staff will advise and assist in securing treatment. Those employees who follow approved treatment will receive disability benefits in accordance with the provisions of established benefit plans and medical insurance coverage consistent with existing plans.

No employee with alcohol or drug dependency will be terminated due to the request for help in overcoming that dependency or because of involvement in a rehabilitation effort. However, an employee who has had or is found to have a substance abuse problem will not be permitted to work in designated positions identified by management as being critical to the safety and well-being of employees, the public, or ExxonMobil. An employee returning from rehabilitation will be required to participate in a Company-approved after-care program. If an employee violates provisions of the employee Alcohol and Drug Use Policy, appropriate disciplinary action will be taken. Such action cannot be avoided by a request at that time for treatment or rehabilitation. If an employee suffering from alcohol or drug dependency refuses rehabilitation, fails to respond to treatment, or fails to meet satisfactory standards of effective work performance, appropriate disciplinary action, up to and including termination, will be taken. This policy does not require and should not result in any special regulations, privileges, or exemptions from normal job performance requirements.

ExxonMobil may conduct unannounced searches for drugs and alcohol on ExxonMobil-owned or controlled property. ExxonMobil may also require employees to submit to medical evaluation or alcohol and drug testing where cause exists to suspect alcohol or drug use, including workplace incidents. Unannounced periodic or random testing will be conducted when an employee meets any one of the following conditions: has had a substance abuse problem, or is working in a designated position identified by management, a position where testing is required by law, or a specified executive position. A positive test result or refusal to submit to a drug or alcohol test is grounds for disciplinary action, including termination. In all circumstances, ExxonMobil retains the right to take appropriate disciplinary action against an employee in possession of or under the influence of drugs or alcohol.

Contractor and vendor personnel at Point Thomson will also be covered by this policy. Those who violate the policy will be removed from Company premises and may be denied future entry.

In addition to the above policy, it is a requirement of ExxonMobil that, as a component of the selection process, applicants being considered for an offer of employment with ExxonMobil must undergo a drug test.

2.1.3 Medical Monitoring [18 AAC 75.007(e)]

Upon beginning work, new hires will receive an entrance physical to establish baseline health conditions and to determine their fitness for duty. Ongoing health assessments will be conducted as required by the type of work performed according to the requirements of the federal Occupation Safety and Health Administration (OSHA) and the Alaska Department of Safety and Health and/or specific company requirements. Emergency response personnel will be scheduled for exams biennially unless the examiner determines a need for a more frequent examination. At a minimum, these medical examinations will include a physical, baseline electrocardiogram, vision screening, and blood work.

2.1.4 Security Programs [18 AAC 75.007(f)]

Point Thomson is remotely located in a sparsely populated area and will not be connected to other North Slope communities by a permanent road. Security plans for similar operations in the area include coordination with local and state police agencies when some unusual security concern or event is experienced. There is some use of the onshore area for subsistence use, and local residents may occasionally pass through the Point Thomson Unit. ExxonMobil understands the need for public access and pass-through, and will provide access as necessary without compromising site control and safety issues. Hunting will be carefully managed around pipeline and other production facilities to prevent intentional or accidental damage, and reasonable precautions are taken (e.g., locking critical valves, land equipment buildings) to discourage and prevent vandalism or sabotage.

Security personnel will be responsible for site access control and assist in enforcing many of ExxonMobil's policies. Access to North Slope operations is controlled through Security checkpoints where Security staff record the personnel present in the operating areas. The security badge system provides a method for monitoring personnel. Each employee or contractor wears an identification badge indicating the employee's company and badge number. With this system, Security has the capability to recognize authorization levels and access personal history information in emergency situations. This program will provide for security and safety of personnel moving to and from the site, and at the site.

2.1.5 Fuel Transfer Procedures [18 AAC 75.025]

Onshore Tanks

Fuel tank trucks of three sizes will operate at Point Thomson, as follows:

- Diesel well service truck rated to 5 psig, nominal 3,000 gallons;
- DOT-specification (vent only), mobile fuel diesel trucks, nominal 4,448 gallons; and
- Produced fluids trucks, nominal 12,180 gallons, with pressure safety valves rated for service, each equipped with two manual valves on the loading lines and a drylock fitting.

Fuel transfer procedures have been developed and implemented for North Slope operations. The *North Slope Fluid Transfer Guidelines* describes practices for safe, responsible transfers of diesel, and will be used for Point Thomson operations. Proper use of surface liners and drip pans is described in the *North Slope Unified Operating Procedures (UOP), Surface Liner/Drip Pan Use Procedure*, May 29, 1999. The UOP mandates the use of liners for:

- Vacuum Trucks,
- Fuel Trucks,
- Sewage Trucks,
- Chemical Delivery Units,
- Chemical Transfer Units, and
- Fluid Transfers within Facilities.

In addition, the fuel truck driver will remain at the truck during loading and off-loading according to ExxonMobil procedures provided in Appendix A. Fuel tank trucks will have drylock fittings and at least one manual valve that isolates the tank from the loading and unloading station. Tank liquid levels can be monitored in either a control room or in the operations warehouse. PSVs, heat-traced vent lines, or pressure relief valves will be installed on all the tanks for vacuum or overpressure protection.

The fuel permanent storage tanks will be equipped with high-level alarms which activate an audible horn to signal that the filling operation must be suspended. Permanent fuel storage tanks will be equipped with level-indicating devices and manual isolation valves with check valves to prevent reverse flow.

Within a facility, transfers involving high liquid levels will activate an automatic shutdown valve by way of an electronic level detector that transmits levels continuously to the constantly staffed facility control room. In addition, individuals will be able to contact the control room via telephone, radio, or visit to determine liquid level at any time.

Personnel transferring fuel will have several communication routes to halt a transfer at any time. In addition to manual witness and local action to close the valve, individuals will be able to contact the control room. A contact with the control room will be mandatory for initial access to the facility. A method for communication will be agreed upon at that time.

Clear work authorization procedures will be used. People involved in fluid transfer at the facility will be specifically trained in accordance with fluid transfer guidelines described in the *North Slope Environmental Field Handbook.*

The fuel tank-truck loading area will be equipped with containment docks to park trucks on during fluid transfer. Fuel storage tanks will be loaded and off-loaded using strict procedures. For transfers between trucks and tanks, manual shutoff valves will be readily available to the truck operator to stop transfers. Trucks will be continuously staffed during fluid transfers. Personnel involved in the transfer will have explosion-proof radios.

Effective communication and planning will be key factors in preventing spills. Pre-job safety meetings will provide employees with information on their role in the overall scope of the work, review guidelines, and stress the importance of avoiding spills.

Fuel flow diagrams, fuel transfer procedures, valving details, and safety precautions for the drill rig will be listed in the drilling contractor's SPCC plan. The SPCC plan for each drill rig will be kept on-site during drilling activities.

Transfers from Barges

The diesel storage tanks will be filled during the summer by transfer from a barge. The barge will be moored to the dock and connected to the tanks via fuel hose. The barge and transfer hose to shore will be surrounded by oil spill containment boom during the entire transfer. Each fuel hose connection will employ a drip pan, and the entire transfer will be closely monitored by barge personnel and facility personnel in accordance with the USCG *Fuel Transfer Operations Manual*. This manual will be submitted to USCG at least 60 days prior to fuel-transfer operations and will be maintained at the Point Thomson facility. Personnel will monitor the hose and the tank level throughout the transfer and will be in communication via radio or hand signals to ensure that the transfer can be quickly stopped if necessary.

Diesel will be brought to the facility during the summer months, and consequently, the transfers will take place during daylight hours. Facility personnel and barge personnel will complete a Declaration of Inspection prior to each operation. The Declaration of Inspection describes communications procedures, start-up and topping-off procedures, and assures that people involved in the transfer have a common understanding of the transfer process. The Declaration of Inspection will be located in the USCG *Fuel Transfer Operations Manual*. In accordance with 18 AAC 75.465, the facility operations leader will do the following:

- Verify that the vessel has an approved State of Alaska contingency plan by viewing the certificate of approval. The response action plan section of the contingency plan must be on board the vessel.
- Complete and sign the contingency plan verification log.
- Submit a copy of the log to the ADEC within the first five days of the month following the transfer.

The transfer hose must have a minimum design burst-pressure at least four times the sum of the relief valve setting plus the static head pressure of the transfer system where the hose is installed (33 CFR 154.500).

2.1.6 Operating Requirements for Exploration and Production Facilities [18 AAC 75.045]

General Facility Requirements

Flow Tests

Liquid hydrocarbons produced during a formation flow test or other drilling operations will be collected and stored in a manner that prevents the liquid hydrocarbon from entering state land or waters. Flow-test liquid hydrocarbons may flow directly to the CPF or will be stored in mobile tanks or the well cleanout tank. Flow-test oil liquids will be stored in mobile tanks, re-injected, or piped to process facilities. Well flow testing and drilling operations will be staffed 24 hours a day. At each shift change, drill site personnel will inspect tank levels and all tankage, sumps, and drains for indications of liquid hydrocarbon leaks. Piping, valves, glands, wellheads, pumps, and all other machinery will also be visually inspected as part of the shift-change routine.

Platform Integrity Inspections and Isolation Valves for Pipelines Leaving Platforms

These requirements do not apply.

Drip Pans and Curbing

Drip pans and curbing will be provided at transfer locations.

Catch Tanks

These requirements do not apply.

Oil Storage Tanks

Oil storage tanks will meet the requirements of 18 AAC 75.065 and .075. Information pertaining to oil storage tanks is in Sections 2.1.10 and 2.1.11 and in Appendix B.

Piping

Piping will meet the requirements of 18 AAC 75.080. Information pertaining to facility piping is in Sections 2.1.9 and 4.9.2.

Well Houses and Well Cellars

Well houses will be sturdy metal frame and panel construction. If an incident occurs that results in a fluid leak inside a well house, the well house walls and roof will confine spray or mist to the inside of the well house.

The well cellar will be a 10-foot by 10-foot square metal unit and will surround the wellhead. There will be insulation between the 20-inch and 34-inch conductors. The insulation will be sealed in place at both the top and bottom to prevent water from getting in between the pipes. The 20-inch and 34-inch conductors will be welded; the connections will not be threaded.

2.1.7 Blowout Control [18 AAC 75.425(e)(1)(F)(iii)]

Well Control Training

ExxonMobil will require certified well control training for drilling supervisors, operations superintendents, drilling engineers, contractor rig drillers, tool pushers, assistant drillers, derrickmen, and other appropriate personnel through an operations training program with a professional organization and in accordance with AOGCC regulations. The curricula will consist of training in blowout prevention technology and well control and Training to Reduce Unexpected Events (TRUE), and result in certification of participants.

TRUE will involve a multifunctional team made up of rig contractor, service company, and operator personnel prior to commencing operations, which will focus on increasing knowledge and awareness to prevent and deal with potential hazards at Point Thomson. The training will be based specifically on Point Thomson development wells, and its goal will be to provide site-specific solutions to potential problems before they occur. Potential hazards will be defined by the team, including well control and lost returns, and action plans will be developed to identify roles and responsibilities, warning signs, how to react to an event, and lines of communication. Special emphasis will be placed on abnormal pressure detection and well control. The training will also establish a team concept and a team approach to identifying and solving problems.

Blowout Prevention

Drilling and completion fluids will provide primary well control during drilling and workover operations. The fluids are designed to exert hydrostatic pressure on the wellbore. The pressure being exerted will exceed the pore pressures within the subsurface formations, preventing undesired fluid flow into the wellbore. Surface-mounted blowout preventer equipment (BOPE) will provide secondary well control. In the event that primary well control is lost, the surface equipment will be used to contain the influx of formation fluid and then safely circulate it out of the wellbore.

The tree, associated valves, and control systems will provide well control during production of the wells. These systems will provide several layers of redundancy to ensure pressure containment is maintained. In the event of a major release of hydrocarbons or a blowout, the response to the situation may involve use of a relief well drilling rig or other well-work equipment to regain well control.

Well Control Planning

Well control will begin during the well planning phase. ExxonMobil has developed an Integrated Pore Pressure Prediction (IP3) Team consisting of reservoir engineers, geologists, drilling engineers, and computer modelers. The IP3 Team will analyze seismic data, well data from exploration wells, and geologic models to predict pore pressure and fracture gradients, and to develop a detailed understanding of the reservoir (Figure 2-2). The use of advanced technology will enable accurate prediction of formation behavior as wells are drilled, and allows the engineer to plan a well that minimizes the risk of a well control incident. In addition, bottom-hole pressure data from other wells in the area and seismic data will be reviewed to ascertain the expected bottom-hole pressure at the proposed well location.

Engineers will use the bottom-hole pressure predictions to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to total well depth. Other factors influencing the mud weight design are shale conditions, fractures, lost circulation zones, under-pressured formations, and stuck-pipe prevention. The well casing program is designed to allow for containment and circulation of formation fluid influx out of the wellbore without fracturing open formations.

Planning is done in accordance with AOGCC requirements. The operator policies and recommended practices are, at a minimum, equivalent to AOGCC regulations.

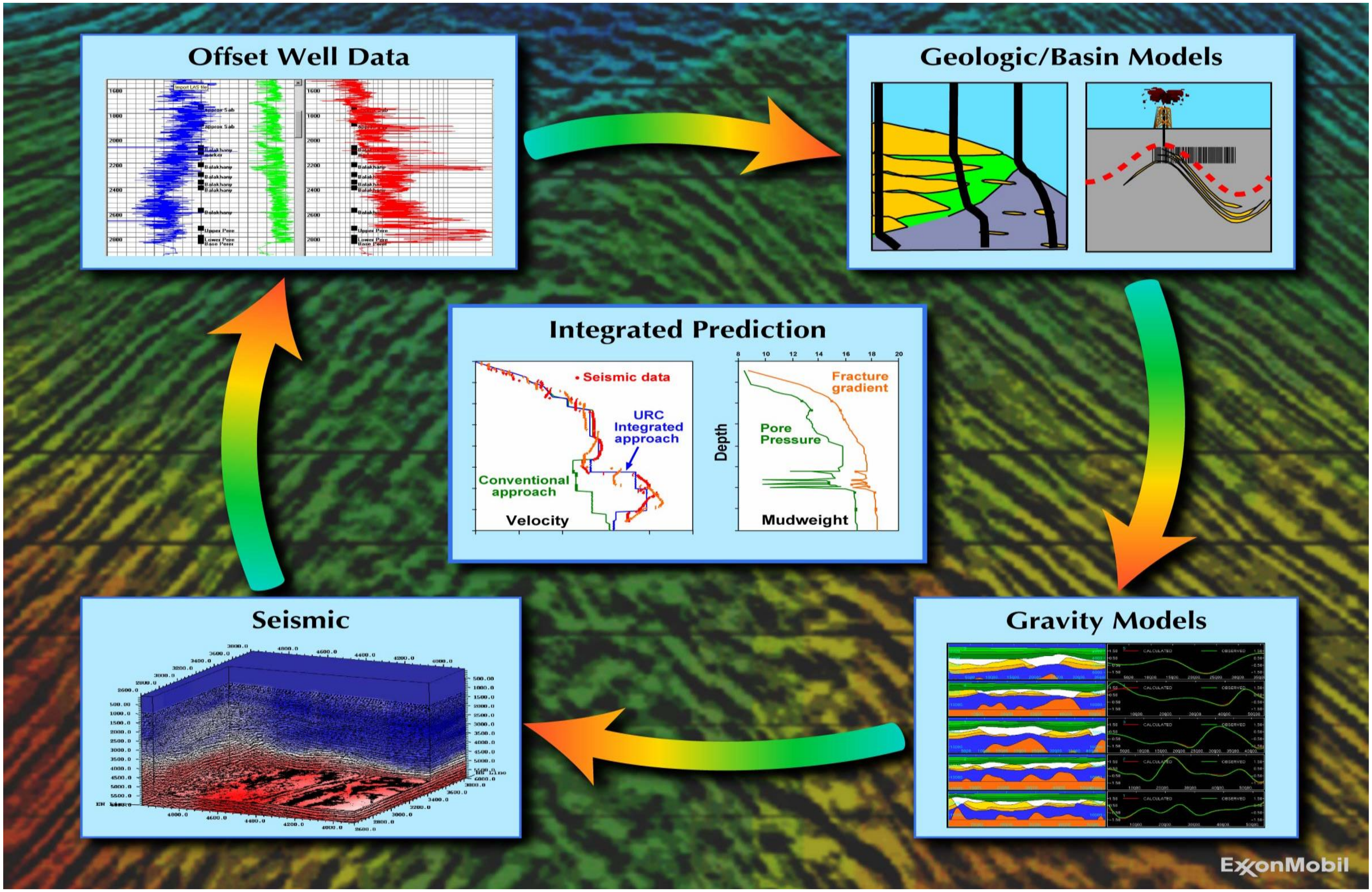
Well Control During Drilling

Inspection of Well Control Equipment

Prior to rig acceptance there will be a comprehensive inspection and testing program performed on the drill rig. Typical items included within this program are:

- BOPE is tested to the full rated working pressure (10,000 psi).
- Choke manifold equipment is tested to the full rated working pressure.
- BOP accumulator unit is tested to confirm that closing times meet American Petroleum Institute (API) standards and meet or exceed AOGCC requirements.
- Precharge pressure and total volume of the accumulator bottles are verified.
- New ring gaskets and seals between each BOP component are installed.
- Pressure integrity testing of the high-pressure mud system is done.
- Inspection of drill string and bottom-hole assembly (BHA) components to the most stringent “T.H. Hill DS-1 Category 5 level” is done. “T.H. Hill DS-1 Category 5 level” refers to an inspection and qualification document written by T.H. Hill Associates, Inc., that is considered industry standard for drill string and BHA inspections and quality control of the drill string equipment.

FIGURE 2-2
TECHNOLOGY INTEGRATION WITH IP3



After successful completion of testing and qualification of the rig BOPE the rig will be accepted for drilling service at Point Thomson. Routine functional and pressure testing during future drilling operations will be conducted in compliance with ExxonMobil and AOGCC requirements.

Methods to Avoid Intersecting Nearby Wells

During drilling operations, there may be a remote chance of intersecting nearby wells producing gas from deeper hydrocarbon reservoirs. The PTU development has been designed with 40-foot well spacing, surface controlled subsurface safety valves (SCSSV) at 4,500-foot total vertical depth (TVD), and directional plans which kick-off the wells at 2,000 feet or shallower. The combination of these design features eliminates the possibility of intersecting another well below an SCSSV, reducing the risk of an uncontrolled blowout.

However, extensive “anti-collision” drilling practices are implemented by the operator and contract directional drilling staff. In the planning stages, survey tool accuracy, downhole equipment types, and directional uncertainties will be converted into a graphical representation with appropriate “close approach” tolerance lines (i.e., drill vs. no drill). Potential zones of near-well interference will be documented and incorporated into the final directional drilling plan. In cases of known interference, either the new well trajectory will be altered or plans will be made to shut in (close SCSSV and vent hydrocarbons above SCSSV) the existing well while drilling the new well. If tolerance lines protecting existing wells are approached during actual drilling operations, drilling operations will cease until a detailed quantitative risk assessment (QRA) can be performed. Drill-ahead QRAs are most often performed on close approach/tolerance line issues. If close approach/tolerance line issues arise while drilling, QRAs will be combined with more rigorous and frequent directional surveying and sometimes with updated wireline directional surveys in the potential intersect well to reconfirm well placement.

Well Control During Surface Hole Drilling

During surface hole drilling a shallow gas blowout can occur when a small, high-pressure volume of trapped gas is encountered. This causes a rapid unloading of the wellbore fluids and gas at the surface in a very short time. A diverter, installed at the wellhead, will be used to divert the shallow gas kick away from the drilling rig. Development wells will use a diverter for drilling surface-hole sections until it can be demonstrated that shallow hazards do not exist on each pad. ExxonMobil will employ this method during surface-hole drilling unless a waiver is received from AOGCC indicating that diverter use is not necessary. A shallow gas blowout will not contain liquid hydrocarbons.

Well Control While Drilling Below the Surface Hole

The surface-mounted BOPE to be used by ExxonMobil exceeds the standards as defined in AOGCC regulation 20 AAC 25.035. The BOPE will be installed after the surface casing is run and cemented. The surface casing is the first string of casing after drilling out from underneath the conductor or structural casing. The surface casing will be set over all potential areas of subsurface drinking water and at a depth that will allow for sufficient formation strength to provide an anchor for the BOPE.

During drilling operations below the surface-hole, the full BOP stack will be necessary because of potential for an influx from the reservoir or other major hydrocarbon zones.

Should an influx occur, the BOP will be used to close in the well, providing a barrier against release of formation fluids to the atmosphere.

BOPE consists of:

- A minimum of four 13 5/8-inch, 10,000 psi working pressure (WP) ram-type preventers;
- One 13 5/8-inch annular preventer (rated to 10,000 psi);
- Choke and kill lines that provide circulating paths from/to the choke manifold;
- A two-choke manifold that allows for safe circulation of well influx out of the wellbore; and
- A hydraulic control system with accumulator backup closing capability as defined in AOGCC regulation 20 AAC 25.035, as a minimum.

Once installed, the BOPE will be tested according to AOGCC requirements. AOGCC field inspectors will typically witness these pressure tests. The AOGCC may allow for an extension past the weekly duration depending on ongoing operations.

Well Control Monitoring and Procedures

Automatic and manual monitoring equipment will be installed to detect abnormal variation in the mud system volumes and drilling parameters. If an influx of formation fluid is taken into the wellbore, the BOPE will be used to immediately shut in the well.

Each well will be drilled according to a location-specific, detailed well plan. While drilling, the well will constantly monitored for pressure control. The mud weight (the primary well control mechanism) will be monitored and adjusted to meet actual wellbore requirements. Too low of a mud weight could under-balance the well, and may result in an influx of formation fluids. Too high of a mud weight may result in lost circulation to a weak formation, which could then lead to a drop in fluid level and an under-balanced condition. Generally, a fairly broad range of mud weight will be used to provide the proper well control for the hole conditions encountered.

If an influx of formation fluid (kick) occurs, secondary well control methods will be employed. Constant monitoring of the total fluid circulating volume and other drilling parameters will ensure that a kick is quickly detected. The well annulus will be shut in using the BOPE. The drill pipe will be shut in by a downhole check valve near the bit and a surface-mounted valve. This will contain the influx and any associated build-up of surface pressure. It will also prevent further influx of formation fluid into the wellbore. Surface pressures will be allowed to stabilize and will then be measured. The pressure readings will enable the calculation of the new kill-weight mud density needed to regain primary well control. A standard well-kill procedure will be implemented to circulate the kill-weight mud and safely remove kick fluids from the hole. Mud-gas separators and degassers will be used to remove gas from the mud as it is circulated out of the hole. After this procedure is completed, the kill effectiveness will be confirmed and the well will be opened up and the fluid levels monitored. Drilling operations will resume when monitors are normal.

BOP drills will be performed on a frequent basis to ensure the well is shut in quickly and properly. The Drilling Supervisor, toolpushers, drillers, derrickmen, and mud engineers at Point Thomson will have International Association of Drilling Contractors- (IADC) certified training renewed every two years in well control. The certified training program will include hands-on simulator practice at recognizing kicks, well shut in, and circulating the kicks out of the wellbore. The success of this training is evidenced by the fact that actual kicks are routinely circulated out and the well made safe.

Backup systems and procedures will be available for surface control of a kick if the above procedure fails to provide the required control. Surface pressures in the annulus and drill pipe provide the required information to determine what is happening downhole. *Bullheading* of formation fluids in the wellbore back into the formation may be required. Pumping down both the annulus and the drill pipe at the same time and forcing the fluids back into the formation can accomplish this. The well is then circulated with kill-weight mud. If it is necessary to bleed off annulus pressure, the choke can be adjusted to control formation fluids. Another technique employed for an underground blowout situation (uncontrolled flow of formation fluids from one formation into another) is the dynamic kill procedure. This entails pumping the kill fluid at a rate high enough to overcome the flowing zone and stop the flow. Depending on the situation, other variations of these basic techniques may be used. Although very unusual, a kick that cannot be killed by normal procedures sometimes occurs. In this case, the use of more detailed procedures is required.

Well Control During Completion

Completion operations (i.e., running the production tubing and associated equipment, perforating the well, and installing the Christmas tree) will occur in a cased hole after the final casing string/liner has been set, cemented, and pressure-tested. Prior to perforating, the cased hole and BOPs provide barriers for running tubing. After installation of tubing, the cased hole, SCSSV, and back pressure valve in tubing hanger provide barriers for nippling down the BOP and nippling up the Christmas tree. The tree and SCSSV provide barriers after perforating the well. During completion operations, well control will be maintained through a minimum of two barriers. Mechanical barriers will be used during completion. Kick-detection equipment and kick management (i.e., equipment, people, training, procedures) are described in the sections above.

Well Control During Workovers

Much of the information provided for well control during drilling is also relevant for rig workover operations. Actual production pressure data will be used to establish workover fluid weights much like offset data are used to establish drilling fluid weights. A minimum of two mechanical and/or fluid barriers will be used prior to removing Christmas trees and installing BOP stacks.

BOPE will also installed during workover operations. The BOPE is capable of controlling the maximum expected wellhead pressure.

Well Control During Wireline/Coil Tubing Interventions

During intervention operations, a minimum of two mechanical barriers will be maintained at the surface. Coil tubing servicing (as opposed to drilling) and wireline operations will be carried out through the Christmas tree. Coil tubing uses high-pressure hydraulic pack-off as the primary well control mechanism, plus a BOP stack consisting of both pipe rams and blind/shear rams.

Wireline also uses a hydraulic pack-off and lubricator as primary well control mechanism, plus a BOP stack with wireline rams.

Well Control During Production

The “Christmas tree” valve configurations for production wellheads on North Slope wells have a minimum of one hydraulically actuated master SSV that can shut in the well, plus additional manual backup valves. Production wells at Point Thomson will be equipped with automatic hydraulic SSVs on the flowline wing valve in addition to the actuated master valve. This is in compliance with AOGCC 20 AAC 25.265. Production wells will also be equipped with SCSSVs.

Both automatically actuated SSVs are connected to the ESD system. In the event of a production shutdown or control-line pressure loss, the valves will automatically shut and wells will cease producing. The SSVs can also be remotely actuated by Point Thomson personnel to shut in production. The SSVs are a “fail-closed” design (loss of hydraulic pressure results in the SSVs closing). If the SSVs do not provide a 100 percent seal, two manual valves on the tree can be opened/closed by personnel. In the event of a leaking flange, valve, or tree/wellhead, component production can be stopped and remedial actions taken depending upon severity. This may or may not involve removing the tree.

Christmas tree SSVs and downhole SCSSVs are integral to the ESD system. The ESD system allows for complete surface isolation from several remote locations. Activation of the individual wellhouse ESD systems will result in surface (SSV) and subsurface (SCSSV) isolation, effectively shutting in the wells.

2.1.8 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AAC 75.055]

Although a specific leak detection system manufacturer has not been selected, current analysis of the pipeline 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. The Point Thomson condensate export pipeline leak detection system will meet the requirements of 18 AAC 75.055 by means of the following:

- Continuous capability to detect a daily discharge of not more than 1 percent of daily throughput,
- Flow verification capability through an accounting method at least once every 24 hours,
- Weekly aerial surveillance for inaccessible pipelines, and
- Ability to stop incoming flow of condensate within one hour after discharge detection.

Leak detection for the condensate export pipeline will consist of monitoring flow and pressure variations in the pipeline, and visual surveillance. The pipeline leak detection system will monitor the condensate export pipeline from the CPF to the Badami tie-in. Detailed information on leak detection system components is found in Section 4.7.

For safe operations, the condensate export pipeline system will include state-of-the-art leak detection instrumentation interconnected to the process facilities via a Supervisory Control and Data Acquisition (SCADA) system. Instrumentation will be designed to help operators recognize potential problems including communication failures, instruments out of range, conditions that may indicate loss of wiring integrity, and other hardware malfunctions.

Isolation valves will be installed at the CPF and Badami tie-in. In addition to the valves, the equipment involved in the leak detection system includes the following:

- Flow meters installed at the inlet and outlet of the pipeline,
- Pressure and temperature indicators at each flow meter location (to improve the response time of the system), and
- A communications link with the SCADA system capable of updating the information as required by the leak detection system.

The system will be calibrated to detect a daily discharge equal to not more than 1 percent of daily throughput. Mass balances will be performed over several specific time intervals. It should be noted that leak tolerance thresholds may be adjusted to prevent nuisance alarms. Flow calculations and/or visual surveillance of the pipeline may be considered by the production control operator before a pipeline shutdown. Visual spill detection for the pipeline will be facilitated by the aboveground construction where pipeline valves, flowline connections, and most associated equipment is visible.

In the event of a catastrophic rupture of the pipeline, the control operator would immediately detect a total loss of pressure while simultaneously observing no reduction in flow. Confirmation would take several minutes, leading to immediate shutdown of the pipeline. In the event of a chronic leak, an integrity alarm will sound if there is a volume variance above specified limits for the related time intervals. The board operator would then proceed through a series of steps to determine the cause of the alarm. Verification of a leak would result in pipeline shut-in. Incoming flow can be stopped within one hour of discharge detection.

2.1.9 Facility Piping Requirements for Oil Terminal, Crude Oil Transmission Pipeline, Exploration, and Production Facilities [18 AAC 75.080]

Corrosion Management Program

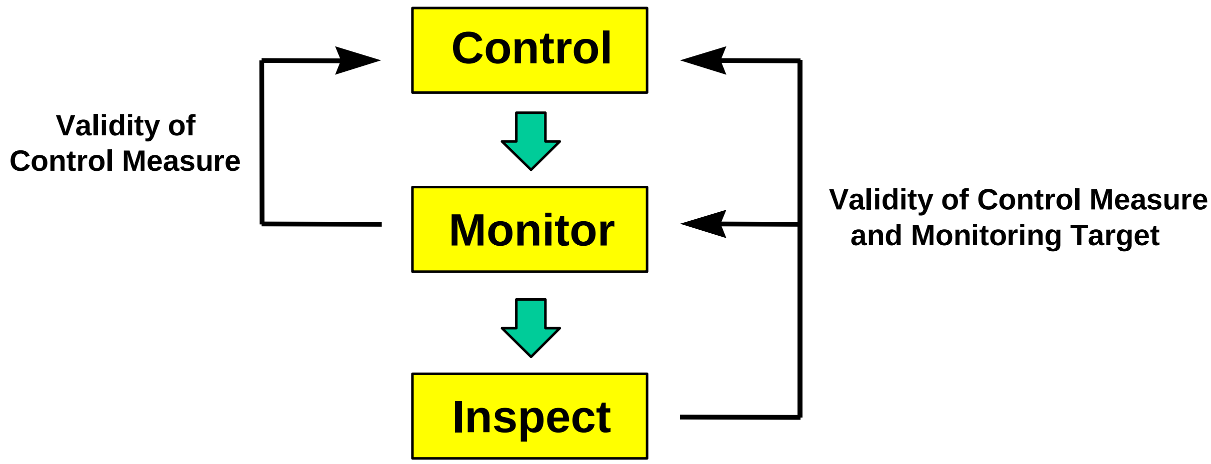
Point Thomson's Corrosion Control Program is a part of the Point Thomson Corrosion Management Program, which covers flowlines, well lines, wellheads, headers, pressure vessels, and tanks, as well as other field and facility piping systems throughout Point Thomson. This section describes corrosion management for facility piping.

Corrosion control is the action of preventing or reducing corrosion to acceptable levels. Corrosion control measures encompass a range of alternatives including chemical inhibition, materials selection, coatings, cathodic protection, and process control. These may be applied individually or in combination. Corrosion monitoring is the measurement of success of the corrosion control activities. In this context, corrosion monitoring is taken to mean any activity that monitors corrosion.

The control and monitoring programs are linked, with the monitoring elements providing feedback on the success of the control elements, as shown in Figure 2-3.

Monitoring programs track the performance of the control programs, giving feedback over time. Examples include corrosion probes and coupons. They are not used to monitor pipe wall corrosion directly, but provide performance indicators of the effectiveness of corrosion control inspection programs that share similarities with monitoring programs that measure corrosion directly. Inspection provides documentation of equipment fitness for service. Examples include ultrasonic testing, radiographic testing, and smart pig inspections.

FIGURE 2-3
THE RELATIONSHIP BETWEEN CORROSION CONTROL AND MONITORING PROGRAMS



Corrosion Control

The applied corrosion control measures reflect the active or potential corrosion mechanisms in the relevant system. For Point Thomson's gathering and export pipelines, these can be broadly subdivided into internal and external corrosion mechanisms.

Internal Corrosion: Internal corrosion is not anticipated for the Point Thomson condensate export pipeline, as only "sweet", dehydrated condensate with a maximum water content of 0.3 percent will be transported through the pipeline. Internal corrosion is not anticipated for the gathering lines as the metallurgy of the pipe is chosen to resist any anticipated corrosive products. As a prudent design measure, internal and external corrosion, although unlikely, will be inspected using smart pigs.

Corrosion monitoring and mitigation tools for the construction, commissioning, and operation of the pipelines are chosen based on good engineering practices and operational experience and may include corrosion inhibitors, biocides, oxygen scavengers, corrosion weight loss coupons, electrical resistance probes, non-destructive examination inspection techniques, smart pigs, visual inspections, Kinley caliper surveys, monitoring of process flow conditions, and bioprobes.

External Corrosion: Piping associated with process operations at the Point Thomson facility will not be below grade. Transfers from a tank barge to the diesel storage tank will be accomplished using a fuel transfer hose.

The sales condensate pipeline will be welded and corrosion protected at road crossings as required by 18 AAC 75.080(b)(1)(A). The sales condensate pipeline will be lowered, enclosed in another pipe or culvert, and covered by gravel at the road crossings. There will also be a diesel pipeline from the diesel tank area to the generator and a gas pipeline from well area on the CWP to fuel the turbines. These pipe segments will also be below grade in vaults and corrosion protected. Cased and vaulted piping segments will not be readily accessible for external inspection; therefore, cased and vaulted piping inspections will not be conducted seasonally.

Corrosion Data

Point Thomson will use corrosion monitoring and inspection data to manage the corrosion control program. The corrosion monitoring program may generate data from corrosion probes, coupons and/or inspection. Each type of data has its benefits and limitations; therefore the data from corrosion probes, coupons and inspection will be viewed as complementary and used in concert in managing the corrosion control program. These monitoring techniques, together with process data, will allow a clear picture to be formed of corrosion activity in the equipment. All process equipment will be covered by the corrosion monitoring program.

The data from the corrosion control, monitoring, and inspection programs will be handled with an electronic database for analysis of current and historical data. In addition to periodic reviews of current data, more in-depth reviews will be conducted looking for broader changes or trends.

Corrosion Inspection Activities

The export pipeline is designed to allow internal inspection by the use of wall thickness measurement pigs, 3-Dimensional geometry pigs and mechanical caliper pigs. The frequency of inspection is currently undetermined, but will be developed to be consistent with the overall corrosion management program.

Buried or Insulated Transfer Piping Outside of Secondary Containment Used to Transfer Oil to or from Docks or Vessels

The facility will not have buried or insulated transfer piping that transfers oil to or from docks or vessels at Point Thomson.

Aboveground Transfer Piping to Transfer Oil from Docks or Vessels

There will not be aboveground piping that transfers oil from docks or vessels at Point Thomson.

Abandonment

Any piping removed from service for more than one year will be drained, identified as to origin, marked “Out of Service,” and capped or blind flanged.

Aboveground Piping and Valves

Aboveground piping and valves will be inspected visually as outlined in Section 2.5.5.

Piping Supports

The overland condensate export pipeline and supports will be designed to resist seismic loads, and they will be seismically stable. The overland pipeline supports will have all-steel structural components. This is the common design practice used for other overland pipeline supports on Alaska’s North Slope, where experience shows that corrosion of the steel components does not readily occur.

Protection of Piping from Vehicles

Any aboveground transfer lines near traffic areas will be protected from damage and marked with reflectors.

2.1.10 Oil Storage Tanks [18 AAC 75.065]

Appendix B contains ADEC regulated stationary oil storage tank data for tanks with capacities greater than 10,000 gallons. Appendix B also lists information on tanks that are regulated by the EPA and have capacities less than 10,000 gallons.

There will be four 12,500-bbl diesel tanks at Point Thomson. The diesel tank facilities will store and dispense diesel fuel for construction, drilling, and operational requirements. The diesel tanks will be sized to meet the fuel needs for drilling, construction, and operations when the ice road and barge routes cannot be used to deliver fuel. The 12,500-bbl diesel tanks are designed to API 650. The tanks will have leak detection systems and an instrumentation and controls system adequate to safeguard the tank storage, loading, and dispensing operations.

The portable storage tanks at Point Thomson will be used for temporary diesel storage. The inventory of portable tanks may vary over time, as facility needs change. Interim portable oil storage tanks, defined as temporary tanks borrowed from other fields or rented from third parties, may be required to support drilling, production, maintenance, or response operations. Oil storage tanks will comply with API Standards 650, 653, and API 12, and state regulatory requirements, where applicable. The ExxonMobil office at Point Thomson will maintain the current inventory for portable tanks in use at the facility.

Inspection and maintenance records for the ExxonMobil-owned permanent and portable tanks will be maintained by ExxonMobil's Corrosion, Inspection, and Chemicals (CIC) Specialist. Before interim tankage is placed into service, CIC will review the tank records to ensure compliance with state regulations, and API 650, 653, and API 12 standards, where applicable. Subsequent inspection, modification, and maintenance records will be kept as long as the tankage remains in service.

2.1.11 Secondary Containment Areas [18 AAC 75.075]

Oil Storage Tanks

Appendix B includes secondary containment descriptions, including volume, and the year the tank is anticipated to be constructed and installed. The appendix also identifies tank loading/unloading areas and describes secondary containment in these areas.

Stationary oil storage tanks will be double-wall and double-bottom construction or will be located within a secondary containment area with the capacity of 110 percent of the largest tank’s volume, unless they have been granted a waiver by ADEC. Diked secondary containment areas will be constructed of bermed/diked retaining walls. The diked containment areas will also be lined with impermeable materials resistant to damage and weather conditions. These areas will be kept free of debris, including accumulated rainwater, and inspected as detailed in Section 2.5.5. Before accumulated snow and water are vacuumed from secondary containment, the areas will be inspected for a sheen. A written record of each drainage/dewatering event will be maintained on a Fluid Transfer Checklist or a North Slope Manifest, which will be completed prior to offloading fluids to the CPF. Fluids offloaded into the plant will be subject to hydrocarbon recovery and water injection. Fluid

Transfer Checklists and North Slope Manifests will be kept on file at the Point Thomson facility. Tanks with double-walls and double-bottoms will be provided with supplemental instrumentation and a means of draining the interstices.

Portable oil storage tanks with a capacity greater than 10,000 gallons will be double-wall and double-bottom construction or will have secondary containment with a capacity equal to at least 110 percent of the tank capacity whenever they are in service. At the jobsite, the tanks will be placed into temporary containment constructed of impermeable liner supported by timbers.

Loading/Unloading Areas

The capacity of the planned loading/unloading secondary containment area is 14,000 gallons. A typical offloading of diesel would be to the local 4,448-gallon mobile fuel truck for transporting to other equipment operating throughout the Point Thomson field. The volume of the largest tank truck compartment using the area will be 12,180 gallons. The only other offloading would be to a well service truck with a volume of approximately 3,000 gallons. Overfill protection devices will be tested before each transfer operation, or monthly, whichever is less frequent.

2.2 DISCHARGE HISTORY [18 AAC 75.425(e)(2)(B)]

The Point Thomson facility is not yet constructed and has no discharge history.

As described in Section 2.1.1, OIMS ensures continuous improvement in environmental performance. When a discharge does occur, the cause, effect, and corrective and preventive measures will be recorded, studied, and become a part of OIMS. From OIMS analysis, training and/or maintenance programs will be implemented to prevent future spills.

2.3 POTENTIAL DISCHARGE ANALYSIS [18 AAC 75.425(e)(2)(C)]

Table 2-1 identifies potential spill sources, the types of failures that may occur, estimates of spill sizes, and appropriate secondary containment measures.

2.4 CONDITIONS INCREASING RISK OF DISCHARGE [18 AAC 75.425(e)(2)(D)]

Conditions specific to ExxonMobil North Slope operations that potentially increase the risk of discharge, and actions taken to eliminate or minimize identified risks are summarized below.

- **High Temperature:** Heat may cause gases to expand, increasing the likelihood of discharge. North Slope facilities are engineered to accommodate temperature fluctuations.
- **Low Temperature:** Low temperature could cause some materials to become brittle or to contract differentially, increasing the risk of equipment failure. Fluids in pipes and tanks could freeze or become gelatinous, potentially rupturing pipes or tanks, as well as reducing the ability to pump fluids. Valves or other equipment could ice over or otherwise freeze, not allowing them to operate as necessary to prevent discharges. North Slope facilities are specifically engineered to accommodate Arctic conditions.

TABLE 2-1
ANALYSES OF POTENTIAL DISCHARGES

TYPE	CAUSE	PRODUCT	SIZE	DURATION	ACTIONS TAKEN TO PREVENT POTENTIAL DISCHARGE
Diesel transfer to tank truck	Tank overfill	Diesel	30 gallons	30 seconds	Transfer procedures
Diesel transfer from barge to diesel tank	Hose rupture	Diesel	440 to 880 gallons	1 to 2 minutes	Transfer procedures; hose watch
Diesel tank	Tank rupture	Diesel	2,733 bbl	Instant	Double-wall; engineering design; tank inspection program
Pipeline	Leak below detection limits	Condensate	428 bbl	7 days	Engineering design; redundant leak detection systems; smart pig analysis/corrosion monitoring
Blowout	Uncontrolled flow from wellbore	Condensate	723 bbl	15 days	Blowout prevention equipment; voluntary ignition of the source

- **High Pressure:** The Thomson Sand reservoir is higher pressure than other North Slope fields. The drilling program will incorporate the use of at least two safety barriers at all times, the drilling mud and BOPE. Specific BOPE is chosen based on well design and the expected pressure and temperature. Likewise, facility design includes constructing pipelines, vessels and valves rated for high pressure.
- **Weather Conditions:** Icy roads, whiteout conditions, and cold snaps present obvious hazards to field operations. Security's strict enforcement of vehicle safety, speed limits, and the posting of warning signs assist in minimizing the potential for vehicular accidents that may result in a spill. In addition, North Slope facilities are engineered to withstand Arctic conditions.
- **Traffic Patterns:** Changes in traffic patterns may increase the risk of vehicles colliding with well lines. Security's strict enforcement of vehicle safety, speed limits, and the posting of warning signs or traffic cones will help to minimize the potential for vehicular accidents that may result in a spill.
- **High Water/Ice:** High water and/or ice during break-up could increase the risk of discharge over river crossings. Vertical support members (VSMs) will elevate the pipeline above the water, and stream crossings will be designed to accommodate high break-up flows.
- **Age of Facilities:** As the PTU field ages, the discharge potential increases. To minimize spills related to aging facilities, ExxonMobil will use a computerized preventive maintenance system, have a corrosion program, perform valve inspections in accordance with AOGCC regulations, have a leak detection system, and conduct regular visual inspections.

2.5 DISCHARGE DETECTION [18 AAC 75.425(e)(2)(E)]

2.5.1 Drilling Operations

Each drilling rig will have a system of controls, monitors, and procedures to assist in the early detection of potential discharges. For both downhole and surface operations, these detection systems will include automated monitoring devices as well as standard operating procedures (SOPs) governing the handling and containment of fluids.

During downhole operations, much of the discharge detection effort will center on well control with an emphasis on detecting wellbore influx (kicks) early. The primary control to prevent a discharge associated with a kick is the density of the drilling fluid in the wellbore. The fluid density and other critical parameters will be monitored closely 24 hours a day by drilling fluid specialists and trained members of the rig crew. The well control equipment will include several independent kick detection devices. The SOP dictates that these systems are monitored 24 hours a day by rig crew members trained in well control to further ensure the timely recognition of and defense against potential spill events.

Kick detection systems will use automated equipment, and visual and/or manual detection in combination with policies and procedures governing the handling and containment of fluids. Rig pit systems will be equipped with pit volume totalizers (PVT) that constantly monitor pit-volume gain and loss. Unexpected gain or loss of drilling fluid will immediately alert rig personnel, who will initiate countermeasures to ensure well control is maintained.

All rig surface support systems will be inspected twice during each 24-hour day for fuel or oil discharges and/or potential leaks. Fluid transfers associated with drilling operations will be carefully planned and monitored using ExxonMobil fluid transfer guidelines. Strict adherence to these procedures will ensure immediate detection of spills associated with fluid transfer operations and significantly reduce the probability of occurrence.

2.5.2 Automated Methods for Processes and Tanks

Automated control systems and visual monitoring of instrument/control panels at the CPF will be used to control flow rates as well as detect potential discharges and process upsets. The control systems and instrumentation will consist of a process control system, as well as a simultaneous independent Safety Instrumented System (SIS/ESD). This redundancy will limit the scope of any single failure. An ESD can be initiated by process conditions outside set limits, or manually by operators at the instrument/control panels. Process conditions that will trigger the SIS/ESD system include either an excess or loss of pressure in a pipeline or equipment malfunction within a production facility. The SIS/ESD system will be provided and maintained for the explicit purpose of stopping hydrocarbon flow when these pipeline or facility problems are encountered. A cascading shutdown system will be used to shut in wells and pipelines prior to relieving pressure on vessels or other process systems at the production facilities. The facilities will also be inspected from the ground on a routine basis for detection of spills and equipment malfunction.

The Integrated Control and Safety System (ICSS) will monitor and operate the oil production wells, process facilities, and pipelines. The ICSS will involve microprocessor-based distributed systems that employ three major categories of digital instrumentation and control, integrated into a single integrated system. The three categories are the DCS, SCADA, and the SIS. The combined system will interface with the communications network.

Operators will control the system through computers. The system will be reliable, as the communications network will be completely redundant. Each of the three planned operator consoles is a separate entity, and critical process loops are under redundant control.

At the process center, control systems and visual monitoring of instrumentation will be used to control injection flow rates, pressures, and distribution. Pressure-relieving devices will be installed on all pressurized units. The facilities will be visually inspected on a routine basis to check for spills and equipment malfunctions.
Production facilities will be continuously monitored with a microprocessor-based DCS. Incoming alarms from the facilities, wells, or pipelines will be documented by date and time. This system capability will allow for the quick tracking of cause-and-effect relationships during upset conditions. In addition, a manually operated, fully automated shutdown system will be available if the computerized system is down and the facilities experience excess pressure or malfunction during production. The production wells will automatically shut in when low producing pressures are detected.

When an emergency requiring shutdown of one or all of the facilities occurs, the SIS will be used. The SIS will be integrated with the DCS. The SIS processor can accept operator commands and transfer status/alarm information to the main operator's console. Redundant SIS systems will provide maximum system integrity for performance of ESD functions.

Lines connecting condensate-producing wells will be equipped with low-pressure transmitters to isolate producing wells in the event of a line rupture. If the operating pressure in the line drops below 150 psi, the line will shut in. Small leaks that would not activate the low-pressure switch would be identified by operations personnel performing routine checks. Given that production fluids are mostly gas and water, with smaller amounts of oil, leaks would involve relatively large amounts of visible steam and gas, which are easily identified by both sight and sound. If small leaks occur, manual steps will be taken immediately by operational personnel to isolate the leak.

The 12,500-bbl diesel oil storage tanks will be fitted with a liquid level transmitter for control room monitoring.

2.5.3 Pipelines

Point Thomson Condensate Export Pipeline

The condensate export pipeline will include state-of-the-art leak detection instrumentation which will be connected to the process facilities control room. The daily operation of the pipeline will be monitored on a continuous basis. Operating personnel will be provided real-time information on pipeline status. For correct operation of the system, regular checks will be conducted on the equipment employed, including the hardware and associated software. In addition, weekly aerial surveillance of the pipeline will be performed.

Monitoring pipeline conditions is also an important part of leak detection. Information on the wall thickness will be obtained by pigging devices that run at predetermined time intervals. The pipeline will be capable of accommodating inspection pigs to obtain information to provide early warning of potential leak points or pipeline deformation. The inspection pig launchers and receivers will be located at each end of the pipeline. Systematic pig runs will allow operators to monitor trends, which will help forecast maintenance work. After reviewing the results from the inspections runs, preventive and/or corrective actions will be identified and implemented, if required. To ensure the correct operation of the system, regular checks will be conducted on the equipment, including the hardware and associated software.

Export pipeline inspection, maintenance, and repair will be performed in accordance with DOT regulations and the right-of-way lease issued by ADNR. Records will be maintained on site.

Point Thomson Gathering Lines

The primary leak detection method for the gathering lines will be visual inspection. In addition to visual inspection, each gathering line will have pressure transmitters to detect low line pressure caused by a catastrophic line rupture. The pressure transmitters will interact with the control system to indicate closure of the inlet valves of each well and outlet shutdown valves upon detection of line pressure outside the acceptable range.

2.5.4 Fire and Gas Alarm System (Process Areas)

The Fire Alarm System is comprised of both a network of individual fire control panels in the CPF and some fire control panels which are not in the network (due to distance limitations). Each fire control panel receives signals from flame, heat, and smoke detectors and activates notification alarms. Gas detectors send their analog signals to the SIS. Upon low- and high-gas level determination by SIS, digital signals are hardwired to the Fire Alarm System which activates the notification alarms.

The Fire Alarm System activates the fire suppression system and notification alarms in response to a fire or low/high gas detection. The fire and gas detection system works in conjunction with the safety shutdown system to provide executive action as required.

All fire and gas system points are transmitted on redundant data links to the PCS. The PCS, in the constantly attended CCR, will monitor, display, alarm, and historize all fire and gas system point status, alarms, and faults. In addition, a dedicated Fire Alarm System Annunciator and a Priority 1 Annunciator will display alarms in the CCR. The Fire Alarm System also historizes fire-system events.

The fire and gas systems may be bypassed to enable maintenance testing. The bypass condition will be alarmed and historized at the CCR and remain active until the system is restored to normal. If a fire or gas condition is detected while in bypass, alarms will activate, but the automatic fire suppression system and executive actions will not respond. Operations personnel would be required to initiate response to the event.

2.5.5 Inspections

General Drillsite, Pad, Flowline, Gathering Lines, Oil Transmission Line, and Facility Inspections

Detection of liquid hydrocarbon discharge from multi-phase flowlines, the condensate export line, permanent and portable tanks, drillsite equipment, and facilities in general will be supported by visual inspections (surveillance). Visual field inspection forms will be completed by operations and security personnel on a daily basis and by other groups, as dictated by their activities and corresponding procedures.

Routine visual inspections of drillsites, pads, and facilities will be significant and productive. The North Slope operators, in a continuing effort to enhance field-wide best management practices (BMP), have developed field inspection guidelines. Table 2-2 outlines the specific requirements for visual surveillance and the groups responsible for performing these surveillances. The ACS Technician is available to help with reporting and/or cleanup activities.

Pad and facility operators will regularly conduct inspections and be trained to look for the following:

- General liner use,
- Fuel tanks (location, liner use, secondary containment),
- Barrels (location, leaders, or lying down),
- Overturned containers,
- Loads secured,
- Leaking equipment,
- Spills or spots,
- Gravel pushed off the road or pads,
- Off-road vehicle travel,
- Animal situations, and
- Equipment refueling.

Multi-phase flowlines, which will move produced fluids from the wellhead to the drillsite manifold, and multi-phase gathering lines, which will move produced fluids from the drillsite manifold to the production facility, will usually be inspected at least monthly, as required by 18 AAC 75.080.

More specifically, the following groups will support the visual inspection process:

- **Security** will contact ExxonMobil's site supervisor when it observes a leak or spill. Security will also complete pipeline inspection forms and contact the spill reporting telephone line to report observed oil or gas discharges during planned inspections of the condensate export pipeline, and upon request during inspections of select gathering lines.
- **Employees** will be responsible for conducting visual inspections of their work areas and reporting spills and leaks to their supervisors.
- **Contractors** will be responsible for visual inspections of work areas and cleaning up spills they may cause.
- **Environmental staff** at Point Thomson will support and verify spill response and clean-up efforts.

2.6 RATIONALE FOR CLAIMED PREVENTION CREDITS [18 AAC 75.425(e)(2)(F)]

ExxonMobil is claiming prevention credits at Point Thomson for the RPS volumes for the well blowout, diesel tank rupture, and export pipeline condensate spill response scenarios.

TABLE 2-2
VISUAL SURVEILLANCE SCHEDULE

INSPECTION	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION REQUIREMENTS	FREQUENCY REQUIREMENT	REGULATORY CITATION	RECORD KEEPING
Oil Storage Tanks	Facility Personnel	EPA	Visual inspection of tanks, piping, and drain valve	Regular	112.8(c)(6), 112.8(d)(4), 112.9(d)(1) and Appendix F, 1.8.1.1	Weekly reading sheet filed in Document Control
		ADEC	Visual inspection of external condition of storage tanks	Monthly	18 AAC 75.065, following API 653 Sections 4.3.1.1 and 4.3.1.2	Visual field inspection form, maintain records for service life of tanks
Secondary Containment Areas for Oil Storage Tanks where applicable	Facility Personnel	ADEC	Visual inspection for oil leaks or spills	Daily at staffed facilities, monthly at unstaffed facilities	18 AAC 75.075(a)(3)(A)	Visual field inspection form
		EPA	Visual inspection	Regular	40 CFR 112 Appendix F, 1.8.1.3	Visual field inspection form, maintain records for 5 years
Crude Oil Transmission Line, Aboveground Flowlines, Multi-Phase Gathering Lines, and Facility Piping and Valves	Facility and Field Personnel and Security	ADEC	Visual inspection of piping and valves	Monthly or during routine operations, if more frequent	18 AAC 75.080(f)	Daily field shift log
Wellhouses and Pads	Field Production Personnel	ADEC	Visual inspection of wellhouses, well cellars, process modules, and well lines	Daily	18 AAC 75.080(f)	Wells daily review sheet filed in Document Control
Condensate Export Pipeline	Security	DOT	Surveillance of condensate export pipeline right-of-way	26 times a year, not to exceed 3 weeks between surveillances	49 CFR 195.412(a)	DOT Pipeline Inspection Checklist Report
	Aviation	ADEC	Aerial surveillance of 16 miles inaccessible to on-the-ground inspection	Weekly, unless precluded by safety and weather conditions	18 AAC 75.055(a)(3)	Aviation log
	Facility and Field Personnel and Security	ADEC	Visual inspection of piping and valves	Monthly or during routine operations, if more frequent	18 AAC 75.080(f)	Daily field shift log

2.6.1 Well Blowout RPS

The following prevention credits are claimed for the well blowout RPS, in accordance with 18 AAC 75.434(c), Response Planning Standards for Exploration or Production Facilities, and/or based on other prevention measures in place at Point Thomson.

- 5 percent prevention credit for drug/alcohol testing [18 AAC 75.434(c)(1)],
- 5 percent prevention credit for well control training for tool pushers and drillers [18 AAC 75.434(c)(2)],
- 5 percent prevention credit for real-time bottom-hole pressure measurements [18 AAC 75.434(c)(4)],
- 5 percent prevention credit for a computer-aided management system for inspection, maintenance, and repair [18 AAC 75.434(c)(5)],
- 5 percent prevention credit for formal safety analysis [18 AAC 75.434(c)(6)],
- 5 percent prevention credit for SCSSVs for emergency shutdown [18 AAC 75.434(c)(7)],
- 10 percent prevention credit for the Operations Integrity Management System,
- 5 percent prevention credit for assurance of well tubular integrity,
- 5 percent prevention credit for an on-site mud system,
- 5 percent prevention credit for overbalanced drilling confirmation technique, and
- 10 percent prevention credit for a five-preventer BOP stack.

Drug and Alcohol Testing

ExxonMobil will have a substance abuse program in place at Point Thomson (Section 2.1.2) and will provide a drug-free workplace for employees and contractors. Employees and contractors will adhere to ExxonMobil drug and alcohol testing procedures and policies, and contract-company drug and alcohol policies will be required to be at least as stringent as ExxonMobil policies. These policies include random drug screening, testing for cause, and search and seizure. Any employee that does not comply with these policies will be subject to disciplinary action up to and including termination of employment. Approximately 25 percent of ExxonMobil Point Thomson employees will be randomly screened on an annual basis.

Well Control Training

ExxonMobil will require certified well control training for Point Thomson drilling supervisors, superintendents, engineers, drillers and tool pushers. The training meets the intent of 18 AAC 75.434(c)(2) and AOGCC 20 AAC 25.527 as an operations training program with certification by a professional organization. The curricula consist of training in blowout prevention technology and well control, and result in certification of participants. Before startup, the Point Thomson rig team will have also received TRUE, which focuses on increasing knowledge and awareness to prevent and deal with potential hazards. Well control training, including TRUE, is described in Section 2.1.7.

TRUE, which involves a multifunctional team made of rig contractor, service company, and operator personnel, will establish a team concept and a team approach to identifying and solving problems. The training will be based specifically on Point Thomson development wells and include practices for high-pressure drilling operations. Special emphasis will be placed on abnormal pressure detection and well control. The goal of TRUE is to provide site-specific solutions to potential problems before they occur. Potential hazards will be defined by the team, including well control and lost returns, and action plans will be developed to identify roles and responsibilities, warning signs, how to react to an event, and lines of communication.

Bottom-Hole Pressure Measurements

ExxonMobil will measure bottom-hole pressure while drilling, with computer-assisted analysis of drilling fluids circulation using a professional organization standard or recommended practice [18 AAC 75.434(c)(4)]. ExxonMobil will use state-of-the-art technology to enhance drilling performance and mitigate risk. Several of the technologies are known as logging while drilling (LWD) and pressure while drilling (PWD). The LWD system enhances early detection of over-pressured intervals or possible lost circulation zones. The PWD directly monitors bottom-hole pressures, enabling the operator to maintain sufficient overbalance without compromising the formation integrity. Early detection of over pressure and maintaining sufficient overbalance while drilling will minimize any chance of incurring a well control event.

As described in Section 2.1.7, ExxonMobil has developed an IP3 Team that will analyze seismic data, well data from exploration wells, and geologic models to develop a detailed understanding of the reservoir. The use of advanced technology will enable accurate prediction of formation behavior as wells are drilled and allow the engineer to plan a well that minimizes the risk of a well control incident.

Real-time data will be presented on a monitor at the driller's console, as well as in Anchorage and Houston. The system will also incorporate full-time monitoring of the circulation and pit systems. It is an improvement on an industry recommended practice that only monitors mud weight in a mud pit before pumping downhole.

Computer-Aided Management of Inspection, Maintenance, and Repair

ExxonMobil will use a computerized preventive maintenance program to help manage inspection, maintenance, and repair of the drilling rig and associated equipment. The contractor's preventive program will be reviewed, gap analysis will be performed, and an agreed-upon, computer-aided system will be followed. The contractor will have the responsibility to maintain the program, while the operator closely monitors the program.

Formal Safety Analysis

ExxonMobil has a formal safety analysis program to manage safety, health, and environmental risks. Elements of the program include incident analysis, emergency preparedness, and risk assessment and management. Effective incident investigations at Point Thomson will provide the opportunity to learn from reported incidents and to take corrective action and prevent reoccurrence. Emergency preparedness will ensure that, in the event of an incident, all necessary actions are taken to protect the environment, employees, and property. Comprehensive risk assessment will be used to reduce risks and mitigate the consequences of incidents by providing essential information for decision-making. The formal safety analysis program is conducted under OIMS, which is further described below and in Section 2.1.1.

Surface-Controlled Subsurface Safety Valves

The Point Thomson drilling program includes the use of BOP and monitoring techniques that exceed regulatory requirements. As an added safety measure, SCSSVs will be in each tubing string to automatically shut in the well if necessary. The ESD system allows for complete surface isolation from several remote locations and is further described in Section 2.1.7.

Operations Integrity Management System (OIMS)

ExxonMobil is committed to conducting business in a manner that is compatible with the environmental and economic needs of communities in which they operate and that protects the safety and health of employees, those involved in operations, customers, and the public. These commitments are documented in ExxonMobil's safety, health, and environmental policies. ExxonMobil's OIMS provides the strategic direction for meeting that commitment, and consists of 11 elements, as shown on Figure 2-1, each of which includes an underlying principle and a set of expectations to be met in the design, construction, and operations of facilities. The well-established OIMS program ensures that all aspects of operations are evaluated for continuous improvement.

OIMS drilling requirements provide numerous detailed and explicit guidelines for planning and implementing safe drilling operations. For example, Element 3 requires ExxonMobil to meet or exceed regulatory requirements and embody responsible requirements where regulations do not exist in design standards. A risk assessment was performed on well control, and in order to manage the risk at Point Thomson, a fifth preventer was incorporated into the BOP arrangement (as described below in this section) and the need to properly train personnel for high-pressure drilling was recognized. Element 5 (Personnel and Training) is used to develop the necessary training programs for the drilling team. OIMS is used extensively throughout ExxonMobil's worldwide organization to ensure risks are properly evaluated and that systems are in place to manage the risk.

Well Tubular Integrity

ExxonMobil's casing and cementing program is designed to provide safe operating conditions for the total measured well depth. Metal-to-metal seals, which are superior to the customary elastomeric seals, will be used in the wellhead for maximum seal integrity. ExxonMobil will test and qualify tubing and casing connections for seal integrity. Casing and tubular connections will be analyzed with finite element analysis and prequalified through physical testing. In addition, the technical specifications for metallurgical properties will be confirmed by testing.

ExxonMobil will use a production liner instead of a full casing string to eliminate the possibility of annular gas flow to the surface. Additionally, cement slurries will be designed to avoid annular gas flow. ExxonMobil's tubing and production casing design policy for this reservoir includes a 12.5 percent collapse safety factor for producing wells, a 25 percent burst-safety factor, and 37.5 percent burst safety factor for surface and protective casing for injection wells.

On-Site Mud System

ExxonMobil will construct a complete mud plant and storage facility to support drilling operations at Point Thomson. The infield mud plant will provide ample capacity beyond the wellsite reserve. This plant will augment the rig systems for both mud mixing and storage during any period when mud requirements are critical. Due to the remote nature of Point Thomson, high-pressure fluid-pumping equipment must reside within the field, and redundant units will be available for immediate use if a well control incident occurs. The mud system is further described in Section 2.1.7.

Overbalanced Drilling Confirmation Technique

ExxonMobil has developed a confirmation technique called the “10/10/10 Test” to help evaluate whether an overbalanced situation exists in the wellbore. This technique may be applied at any point in the well, but will be most valuable when performed in the shale intervals overlying the productive zone (the Thomson Sand). At this point in the well, one necessary component for a kick is missing: the permeable formation. Testing using the 10/10/10 Test can provide accurate and early diagnostics of the formation pressure before the potential kick interval is reached.

The 10/10/10 Test involves circulating the well for 10 minutes to establish background gas, discontinuing mud circulation for 10 minutes to reduce equivalent circulating density (ECD), and circulating the wellbore for an additional 10 minutes. Mud is then circulated from the bottom of the well, without further drilling, to the surface. Gas concentrations are measured and an evaluation is done to determine whether the overbalance is sufficient.

Five-Preventer BOP Stack

A fifth preventer was incorporated into the BOP stack arrangement in order to manage the risk at Point Thomson. A BOP stack with four sets of rams and one annular preventer will be used to drill below surface casing, providing one more preventer than required by AOGCC regulations. The rams and annular preventer will all be rated to 10,000 psi working pressure. This arrangement allows two preventers to close on the casing and liners, and in the case of liners, permits two ram-type and one annular preventer to be used on the drill-pipe running-string without having to stop and change-out rams. The extra ram will also provide added redundancy.

2.6.2 Tank Rupture RPS

Prevention credits are claimed for the diesel tank rupture RPS volume in accordance with 18 AAC 75.432 (d), Response Planning Standards for Oil Terminal Facilities, as follows:

- 5 percent prevention credit for drug/alcohol testing [18 AAC 75.432(d)(1)],
- 5 percent prevention credit for operations training and licensing program [18 AAC 75.432(d)(2)],
- 5 percent prevention credit for on-line leak detection systems [18 AAC 75.432(d)(3)],
- 60 percent prevention credit for secondary containment (provided by double-wall tank construction with leak detection) [18 AAC 75.432(d)(4)],
- 15 percent prevention credit for fail-safe valves on piping systems [18 AAC 75.432(d)(5)(B)], and
- 25 percent adjust for double bottoms with leak detection [18 AAC 75.432(d)(5)(C)].

Drug and Alcohol Testing

ExxonMobil has a substance abuse program in place, which includes testing as described briefly above under Well Blowout RPS and more thoroughly in Section 2.1.2.

Operations Training and Licensing Program

ExxonMobil's training for bulk tank-farm operators meets the intent of 18 AAC 75.434 (2)(C)(2), as an operations training program with certification by a professional organization. The curricula consist of training in hazard identification, operating procedures, safe work practices, emergency response and control procedures, management of change, pre-startup safety, incident investigation, and contractor safety and result in certification of participants. Fuel transfer procedures have been developed and implemented for North Slope operations and adopted by ExxonMobil. The *North Slope Fluid Transfer Guidelines* (Appendix A) describe practices for safe, responsible transfers of diesel that will be adhered to during Point Thomson operations.

On-Line Leak Detection Systems

The diesel tanks will have leak detection systems and an instrumentation and controls system that are adequate to safeguard the tank storage, loading, and dispensing operations. The leak detection system is further described in Sections 2.1, 2.5.2 and 4.6

Secondary Containment

ExxonMobil claims a 60 percent prevention credit under 18 AAC 75.432(d)(4) for secondary containment. The tanks will be constructed with double walls and double bottoms and designed with automated leak detection and monitoring.

Fail-Safe Valves on Piping Systems

Automatic valves will be provided on the diesel storage tank piping systems as described in Section 4.2.3. Automatic valves provide the most effective means to stop the flow of oil into tanks whose levels are constantly changing.

Double-Bottom Tanks with Leak Detection

ExxonMobil claims a 25 percent prevention credit under 18 AAC 75.432(d)(5)(C) for double bottoms with leak detection.

2.6.3 Condensate Export Pipeline RPS

The following prevention credits are claimed for the RPS volume for the condensate export pipeline spill scenario in accordance with 18 AAC 75.436(c), Response Planning Standards for Crude Oil Pipelines.

- 5 percent prevention credit for drug/alcohol testing [18 AAC 75.436(c)(1)],
- 5 percent prevention credit for on-line leak detection systems [18 AAC 75.436(c)(3)], and
- 15 percent prevention credit for instrumented in-line cleaning and diagnostic equipment, also known as smart pigs [18 AAC 75.436(c)(4)(B)].

Drug and Alcohol Testing

ExxonMobil has a substance abuse program in place, which includes testing as described briefly above under Well Blowout RPS and more thoroughly in Section 2.1.2.

On-line Leak Detection Systems

The leak detection systems to be used at Point Thomson are described in Sections 2.1.8, 2.5.3, and 4.7.

Instrumented In-line Cleaning and Diagnostic Equipment (Smart Pigs)

The condensate export pipeline will use smart pigs for diagnostics and corrosion control, as described in Section 2.1.8.

2.7 COMPLIANCE SCHEDULE AND WAIVERS [18 AAC 75.425(e)(2)(G)]

Not applicable.

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