OCS Report
MMS 98-0012

Investigation of Blowout and Fire, Platform A, Eugene Island Block 380, Lease OCS-G 2327, January 24, 1996,

Gulf of Mexico, Off the Louisiana Coast

MMS
U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

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U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office

New Orleans
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Contents

Investigation and Report

Authority

A serious blowout and fire occurred aboard the Sundowner 15 platform rig during the conduct of completion operations for Oryx Energy Company (Oryx) on Lease OCS-G 2327, Well A-17, Platform A, Eugene Island Block 380 in the Gulf of Mexico, offshore the State of Louisiana, at approximately 5:20 p.m. on January 24, 1996. Pursuant to Section 208, Subsections 22(d), (e), and (f) of the Outer Continental Shelf (OCS) Lands Act Amendments of 1978, and the Department of the Interior Regulations 30 CFR Part 250, the Minerals Management Service (MMS) is required to investigate and prepare a public report of this accident. By memorandum dated January 26, 1996, the following personnel were named to the Investigative Panel:

D.J. Griffin	Houma, Louisiana
J.J. Price	Houma, Louisiana
M.J. Saucier	Houma, Louisiana
C.J. Schoennagel	New Orleans, Louisiana

Procedures

On January 25, 1996, Investigative Panel members flew to Eugene Island Block 380, Platform A and photographed the scene from a helicopter. (For photograph of scene, see Attachment 1.) After circling the structure several times, the Investigative Panel members flew to Lease OCS-G 6987, Platform A, Green Canyon Block 6, and conducted interviews and obtained statements from personnel onsite at the time of the blowout. These included the toolpusher, both drillers, and the company representative. The panel members also obtained information from three well control personnel.

On February 28, 1996, Investigative Panel members met in the MMS Houma District office with United States Coast Guard (USCG) personnel to review and discuss information obtained in the investigation and to determine if a formal hearing were necessary. On April 12, 1996, a teleconference was held with panel members, at which time it was determined that enough information had been obtained and a formal hearing would not be needed. However, Investigative Panel members met again in the Houma District office on October 30, 1996, and determined that several events leading up to the blowout needed clarification before the investigation could be concluded.

The Investigative Panel convened on May 16, 1997 at the MMS Regional Office in New Orleans, Louisiana. The following individuals were informally questioned about the accident, including prior and subsequent activities:

Travis Sepulvado	Sundowner
John Grappe	Sundowner
Dennis McDaniel	Oryx
Wanda Parker	Oryx
Kenny Sifford	Oryx

Investigation

Background

Lease OCS-G 2327 covers approximately 5,000 acres and is located in Eugene Island Block 380, Gulf of Mexico (GOM), off the Louisiana coast. (For lease location, see attachment 2.) The lease was issued effective February 1, 1973, for a cash bonus of $13,593,950.00. The original lessee was Sun Oil Company. The lessees at the time of the accident were Anadarko Petroleum Corporation (27%), Sun Operating Limited Partnership (58%), and Burlington Resources Offshore Inc. (15%). Oryx Energy Company was the designated operator of the lease.

On April 2, 1976, approval was received to install an 8-pile, 24-well-slot platform, Platform A, in Eugene Island Block 380. Subsequent to approval, Platform A was installed on November 3, 1976, and 16 wells were drilled.

Oryx received approval to drill Well A-17 on August 29, 1995. Well A-17 was spudded on December 1, 1995, and drilled as a highly deviated well. A total depth of 5,672 feet measured depth (MD), 3,423 feet true vertical depth (TVD), was reached on December 31, 1995.

The lower PL 1-2 sand was perforated in Well A-17 from 5,512 feet to 5,542 feet MD, 3,352 feet to 3,366 feet TVD on January 21, 1996.

Description of Accident

On January 24, 1996, Oryx was in the process of completing the upper PL 1-1 sand in Well A-17. The PL 1-1 sand was perforated from 3,634 feet to 3,660 feet MD, 2,722 feet to 2,729 feet TVD. The perforating guns were pulled from the well and a packer plug retrieving tool was made up to the bottom of the workstring/tubing. The packer plug was then pulled at 3,671 feet MD.

A gravel pack assembly and gravel pack screen were then run in the well. Completion fluid started to flow out the top of the workstring/tubing as it was being worked in the well.

The crew was not able to connect the top drive unit to the workstring/tubing. The blind rams were closed but the flow out the workstring/tubing did not change. Additional rams and the annular preventer were closed. Gas flowing out the workstring/tubing ignited.

Forty-five personnel were evacuated from the rig by two vessels without incident. Within two hours after the fire ignited, the top drive fell to the rig floor. Shortly afterwards, the derrick toppled. The fire extinguished itself about midnight on January 28, 1996, and the well was killed on February 7, 1996.

Findings

Preliminary Activities

Well A-17 was drilled to deplete attic gas reserves from the PL 1-2 sand. When the target interval was logged, it was discovered that the PL 1-2 sand was not as thick as expected. However, the PL 1-1 sand that was thought to be wet was found to be productive. The completion program was then designed to perforate and gravel-pack the two sands independently and set up the well as a single selective producer in the PL 1-2 sand, with the PL 1-1 sand isolated behind a sliding sleeve.

By January 9, 1996, Oryx had completed the running and setting of 7-inch, 23-pound-per-foot, N-80 casing to 5,672 feet MD, 3,423 feet TVD, and cemented the casing with 1,200 sacks of cement. The 4½-inch drill pipe was laid down, and 3½-inch, 9.3-pound-per-foot, L-80, 8 round tubing was picked up and used as the workstring.

On January 10 and 11, 1996, the blowout preventers (BOP's) and related equipment were pressure tested, and the well was cleaned out to the float collar. The casing was pressure tested to 4,000 pounds per square inch (psi), a cement bond log was run, and the 8.6 pound-per-gallon (ppg) seawater was displaced with 9.0 ppg calcium chloride ($CaCl_2$).

On January 14 and 15, 1996, the 7-inch casing was perforated with a 4-inch casing gun from 3,680 feet to 3,681 feet MD to block-squeeze the initial cement job. The perforations were squeezed with 250 sacks of cement, the cement was drilled out, and the squeeze was unsuccessfully tested.

From January 16 through 19, 1996, the perforations were resqueezed with 150 sacks of cement. The BOP's were then tested. The cement was drilled out and the squeeze job was tested. The well was then cleaned up in preparation for perforation and completion of the PL 1-2 and PL 1-1 sands.

Completion of PL 1-2 Sand

A sump packer was set at 5,550 feet MD, 3,369 TVD, on January 20, 1996. On January 21, 1996, the PL 1-2 sand was perforated from 5,512 feet to 5,542 feet MD, 3,352 feet to 3,366 feet TVD, with a 4¾-inch tubing-conveyed perforating (TCP) gun.

The well was shot using a tubing-activated firing head, and there was a full column of 9.0 ppg $CaCl_2$ fluid (743 psi overbalance of formation pressure). The well went on vacuum with fluid loss being monitored for a half-hour at 15 to 20 barrels per hour (BPH). A 10-barrel (bbl) hydroxate ethel cellulose (HEC) pill was mixed and spotted with fluid loss being monitored for a half-hour at 3 BPH. Two stands of the tubing were pulled, and the well was then monitored for a half-hour with fluid loss of ¾ BPH.

A gravel pack assembly and gravel pack screen were then run in the well, and an SC-1 gravel pack packer was set at 5,368 feet MD. (For schematic of PL 1-2 completion, see attachment 3.) A 200-gallon 10 percent hydrogen chloride (HCl) pill was spotted across the perforations to dissolve the HEC pill. Injection rates were established and the perforations were gravel packed with a total of 4,420 gallons of ammonia chloride (NH_4Cl), 2,000 gallons of 10 percent HCl, 4,000 gallons of mud acid, and 1,130 pounds of 30/40 sand.

The crossover tool was picked up above the SC-1 packer at 5,368 feet MD, and a fluid loss of 140 BPH was observed. Two stands of the tubing were pulled to get the washpipe above the knockout isolation/flapper valve (KOIV) at 5,405 feet MD. The well was monitored for a half-hour, with the fluid loss being reduced to ⅛ BPH, indicating that the KOIV was holding. The tubing, crossover tool, and washpipe were pulled out of the well.

On January 23, 1996, the isolation and spacer phase above the PL 1-2 sand was initiated prior to completing the PL 1-1 sand. The tubing was tripped in the well, and a tubing safety valve was installed on the top of the last joint of tubing. The KOIV at 5,405 feet MD was broken and the well went on vacuum. The tubing continued to be tripped in the well until the seals were landed. An SC-1 packer was set at 3,671 feet MD. The tubing was pulled above the spacer KOIV at 3,682 feet MD and zero fluid loss was observed in the well. (For schematic of the isolation and spacer phase above the PL 1-2 sand, see attachment 4.)

Completion of PL 1-1 Sand

A packer plug was made up at the bottom of the TCP guns. The TCP guns and packer plug were tripped into the well within 520 feet of the surface and a cycle reversing valve was closed. The tubing continued to be tripped into the well with 520 feet of air cushion and the rest of the tubing containing 9.0 ppg $CaCl_2$.

On January 24, 1996, the packer plug was snapped into the SC-1 packer at 3,671 feet MD. The PL 1-1 sand was then perforated from 3,634 feet to 3,660 feet MD, 2,722 feet to 2,729 feet TVD, with 4¾-inch TCP guns. The

PL 1-1 sand was shot using an annular pressure fire head, thereby allowing the well to be shot 200 psi underbalanced to the formation pressure of 1,180 psi.

After perforating the PL 1-1 sand, the well flowed back a total of 10 bbl of completion fluid with a recorded pressure of 680 psi flowing tubing pressure (FTP). The well was shut in for 15 minutes with a shut-in tubing pressure (SITP) of 780 psi being recorded. Applied annulus pressure was then bled off to close the downhole tubing valve. The pressure was then bled off the tubing and 27 bbl of completion fluid were used to load the tubing and cycle the downhole reversing valve open.

Two tubing volumes of fluid were reversed out through the reversing valve above the closed downhole tubing valve. The downhole tubing valve was opened by pressuring up on the annulus. The packer bypass was opened by picking up on the tubing string. Fluid loss was monitored for 30 minutes with the rate of fluid loss being approximately 11 BPH.

The well was reversed out again through the packer bypass, and it was then monitored for 30 minutes with the rate of fluid loss being approximately 10 BPH. A 10-bbl HEC pill was spotted in an attempt to reduce fluid loss. The well was monitored for an additional 1½ hours while surface equipment was being rigged down. Fluid loss during this period reduced to 3 BPH.

The TCP guns and tubing were pulled from the well and a packer plug retrieving tool was made up to the bottom of the tubing. The tubing with the packer plug retrieving tool was then tripped back into the well to the SC-1 packer set at

3,671 feet MD. It took approximately 8 hours from the time the TCP guns were pulled from the well to the time when the tubing was tripped back to 3,671 feet MD. During this period the well remained static.

Loss of Well Control

The packer plug set at 3,671 feet MD was pulled with no problems occurring. At this time a rough space-out was made to the SC-1 packer set at 3,671 feet MD. The well remained static as the tubing with the packer plug and retrieving tool was pulled out of the well.

The well continued to remain static as the tubing with a gravel pack assembly was tripped into the well. (For schematic of wellbore with PL 1-1 sand and gravel pack assembly, see attachment 5.) There were a 2⅞-inch washpipe and a low-pressure ball check located below the gravel pack assembly. Three feet of seals were added to the bottom hole assembly so that there would be seals in the packer bore prior to breaking the KOIV at 3,682 feet MD.

On January 24, 1996, at approximately 5:00 p.m., the thirty-eighth stand was picked up and tripped into the well. There was no tubing safety valve installed at the top of the thirty-eighth stand prior to running it into the well. This stand was lowered to break the KOIV and to land the snap latch in the packer at 3,671 feet MD for space-out.

An indication that the KOIV valve was broken came by weight loss of 7,000 pounds as the stand was being run in the well. The space-out occurred after approximately 18 feet of the 38th stand of tubing had been run into the well. This left about 75 feet of tubing above the drill floor when the gravel pack assembly was landed in the packer at 3,671 feet MD. Further indication that the KOIV valve was broken came as 2.2 bbl of fluid was needed from the trip tank to fill the annulus after the initial indication that the valve was broken. The annulus continued to be monitored and remained static indicating that the PL 1-2 perforations were either not in contact with the PL 1-1 perforations or not on vacuum.

The tubing was then picked up so that it could be snapped out of the packer to install a pup joint, tubing safety valve, and the gravel pack surface assembly. As the seals were pulled from the packer, an increase in drag was noticed on the drill floor. After eight feet of tubing were picked up, the tubing stopped coming out of the well. An attempt was made to lower the tubing back in the packer but the tubing would not move. Approximately 75,000 pounds (23,000 pounds over pick-up weight) was then exerted on the tubing to pick it up, but there was no tubing movement.

The slips were installed and one rotation of the tubing was made. Reports indicate the tubing then made a half rotation back. An attempt was again made to work the tubing by exerting 75,000 pounds to pick up the tubing, again with no tubing movement occurring. After approximately 5 minutes of the crew's working the tubing, fluid started to flow out the top of the tubing located some 75 feet above the drill floor.

Attempts to Stop Well Flow

An attempt was made to stab the top drive into the top of the tubing, but it was not successful. A crew member was put in a riding belt and went up to try and manually guide the top drive into the top of the tubing. By this time the flow out the top of the tubing had significantly increased from when the well initially started to flow, and the crew member could not see to guide the top drive into the top of the tubing. During this period no flow was observed from the annulus of the well.

At this point the blind rams were closed in an attempt to reduce well flow. No change was observed in well flow as a result of this action. As gas began to flow out the top of the tubing, personnel evacuated the drill floor. As evacuation of the drill floor was occurring, the pipe rams, annular preventer, and hydraulic control remote (HCR) valves were closed in anticipation of possible annular flow. (For schematic of BOP stack, see attachment 6.) It had no effect on the current well flow.

At this point personnel started to evacuate both the Sundowner 15 rig and Eugene Island Block 380, Platform A. While the evacuation was occurring, the gas ignited and a fire ensued. The Emergency Shutdown (ESD) System for the platform was activated as evacuation was occurring. The ESD system was activated to shut in all wells, both surface and subsurface, thereby preventing them from possibly contributing to the fire.

Subsequent Activities

Oryx and well control personnel arrived via helicopter at approximately 1:45 a.m., January 25, 1996, at Green Canyon Block 6, Platform A, where a temporary operational base was established, These personnel traveled via the motor vessel (MV) *Evelyn M* from Green Canyon Block 6, Platform A, and boarded Eugene Island Block 380, Platform A at daybreak on January 25, 1996. These personnel proceeded to close the manual master valves on all wells in the well bay and on the departing oil and gas sales pipelines. The fire was coming from the tubing stuck in the slips in the rotary table. A visual inspection of the BOP stack indicated that the top set of pipe rams was closed and the blind rams and the bottom set of pipe rams were open. Subsequent investigation of the tubing revealed that the blind rams had activated and closed on the tubing but had probably reopened due to damage to the accumulator system. The personnel who boarded the platform then returned to Green Canyon Block 6, Platform A.

On January 26, 1996, a permanent operational base was established on the derrick barge (DB) *Ocean Builder*. Personnel again boarded Eugene Island Block 380, Platform A and made up a 2-inch kill line from the casing spool below the BOP stack to the back side of the platform. They then ran the line to one of the support vessels, *Jan Tide*. Water was than pumped down the annulus in an attempt to kill the well. The casing pressured up, indicating that fluid could not be circulated down the annulus and up the tubing. The kill procedure was halted, the kill line disconnected from the *Jan Tide*, and the well was left burning to the atmosphere. The *Jan Tide* and another vessel sprayed water on the platform to minimize heat damage to the facility.

Equipment was mobilized to the location by January 27, 1996, to perform well killing and capping operations. Weather conditions prevented any significant operations from being conducted. However, at approximately midnight on January 28, 1996, the fire extinguished itself. A helicopter overflight indicated that the well was venting dry gas. The DB *Ocean Builder* was then positioned beside the platform, anchors were deployed, and a gang plank was constructed for access to the platform.

By January 29, 1996, gas monitoring equipment was installed and well killing equipment was offloaded onto the DB *Ocean Builder* and rigged up for killing operations. On January 30, 1996, removal of the damaged rig parts began. Removal of damaged rig parts and associated equipment continued until February 1, 1996, when weather conditions deteriorated and the DB *Ocean Builder* had to pick up anchors and move off location.

The DB *Ocean Builder* returned on location after the weather cleared on February 5, 1996. The major rig parts, including the draw works, rotary table, and floor section, were removed on February 6, 1996. In addition, all rig parts and gravel pack equipment were removed from the top deck of the platform. Well killing and capping equipment were than moved onto the well site.

On February 7, 1996, the BOP stack was removed except for the bottom set of pipe rams, which were left on the riser joint. After removal of the BOP stack, the tubing was found smashed where the blind rams closed after being activated during the initial phase of the loss of well control. (For photograph of smashed tubing, see attachment 7.) After the tubing above the lower set of pipe rams was cut, a set of blind rams was installed above the set of lower pipe rams.

A well-kill operation was then conducted by first pumping seawater down the tubing, followed by an HEC pill and 11.5 ppg $CaCl_2$. The well was kept full as the blind rams were removed, the tubing cut below the smashed part, and additional rams reinstalled. The well was capped at approximately 3:00 p.m. on February 8, 1996, when a blind flange was installed on top of the BOP stack.

Damages

The Sundowner 15 rig substructure and derrick were completely destroyed in the blowout and subsequent fire. There was severe damage to other parts of the rig and associated equipment. There was minimal damage to Oryx's Platform A. There was no damage to the other wellheads on the platform. The evacuation of the rig and platform was conducted without incident. There was no pollution as a result of the incident.

Conclusions

Probable Cause of Incident

The probable cause of the incident was the failure to maintain a sufficient volume of completion fluids in the well to keep the well overbalanced with the completed sands, thereby preventing influx of formation fluids into the tubing string.

Contributing Causes

The following were contributing causes:

1. The failure to monitor the tubing string visually to ensure that it remained full. The tubing string being landed some 75 feet above the drill floor prevented this from occurring.

2. Running the tubing string in the well without a tubing safety valve being installed at the top of the string.

3. Not properly spacing out the tubing before landing the gravel pack assembly and breaking the KOIV. This allowed the top of the tubing string to be located some 75 feet above the drill floor when the well started to flow.

4. The tubing string becoming stuck in the well. This prevented the tubing from being moved in the well to reengage the seals or out of the well to properly space out and install a pup joint and tubing safety valve.

Possible Contributing Causes

The following were possible contributing causes:

1. Having the packer above the gravel pack assembly partially presetting after breaking the KOIV. This could explain why the annulus remained full while the fluid in the tubing string became insufficient to prevent an influx of formation fluid into the tubing string. It could also explain why the operators could not pump down the annulus to kill the well.

2. Running of the additional three feet of seals at the bottom of the gravel pack assembly. This could have created a hydraulic lock and forced the low-pressure ball check off seat prior to breaking the KOIV. The ball check off seat would have allowed communication of the PL 1-1 sand with the PL 1-2 sand after the KOIV was broken. The high deviation of the well could have contributed to the ball check remaining off seat.

3. Using fine-threaded tubing as a workstring. This made the connection of the top drive with the tubing string extremely difficult to accomplish after the well started to flow out the top of the tubing string.

4. Not running blind shear rams in the BOP stack. Had blind shear rams been installed in the BOP stack instead of blind rams, they may have completely sealed off the well flow out of the tubing if they had been activated.

Recommendations

Regulatory Requirements

The MMS should consider requiring blind shear rams on all installations where blind rams are at present required.

Safety Alerts

The Gulf of Mexico OCS Region should issue Safety Alerts concerning the following:

1. Lessees and operators should consider installing blind shear rams on all installations where they at present install blind rams.

2. Lessees and operators should attempt to lock down rams after they have been activated in an emergency situation.

3. Lessees and operators should consider installing a workstring/tubing safety valve at the top of each stand prior to picking it up when the workstring/tubing is approaching the target area.

4. Lessees and operators should attempt to space out such that operations can be conducted from the rig floor prior to hitting the target area.

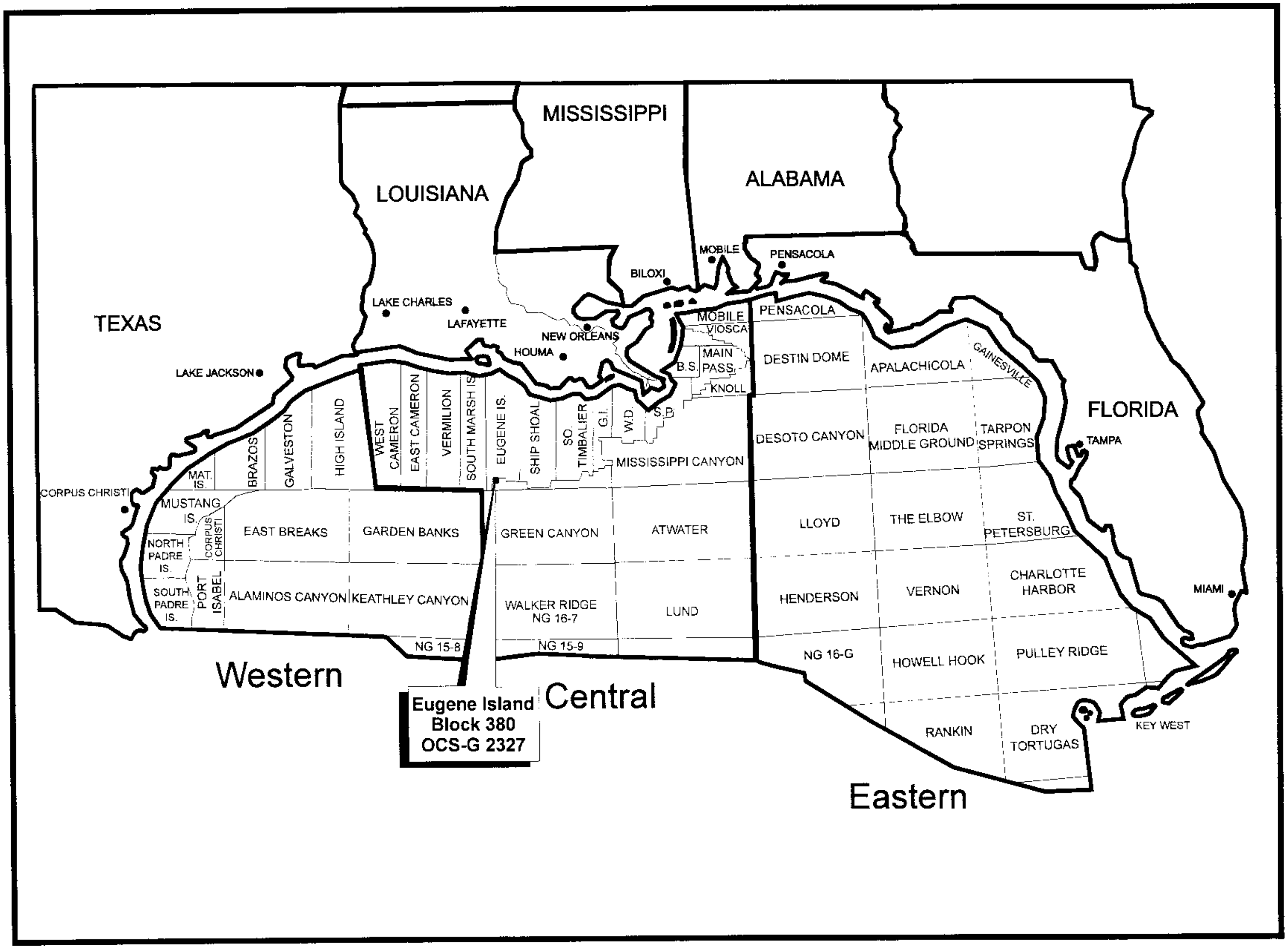
Additional Considerations

The MMS should conduct a study to see if the ball check coming off seat is an inherent problem in highly deviated wells.

Attachment 1

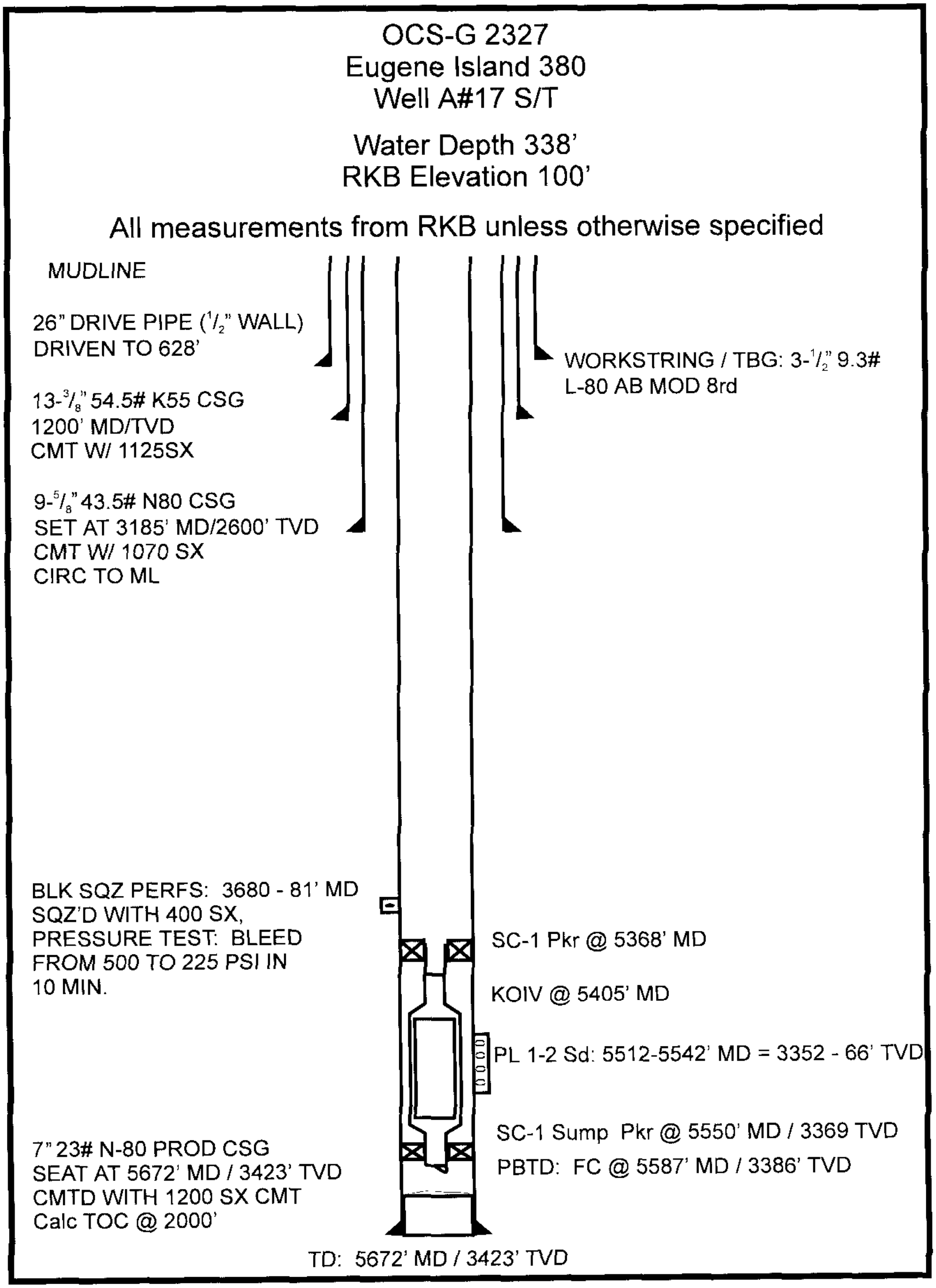
Photographs of scene

Attachment 2



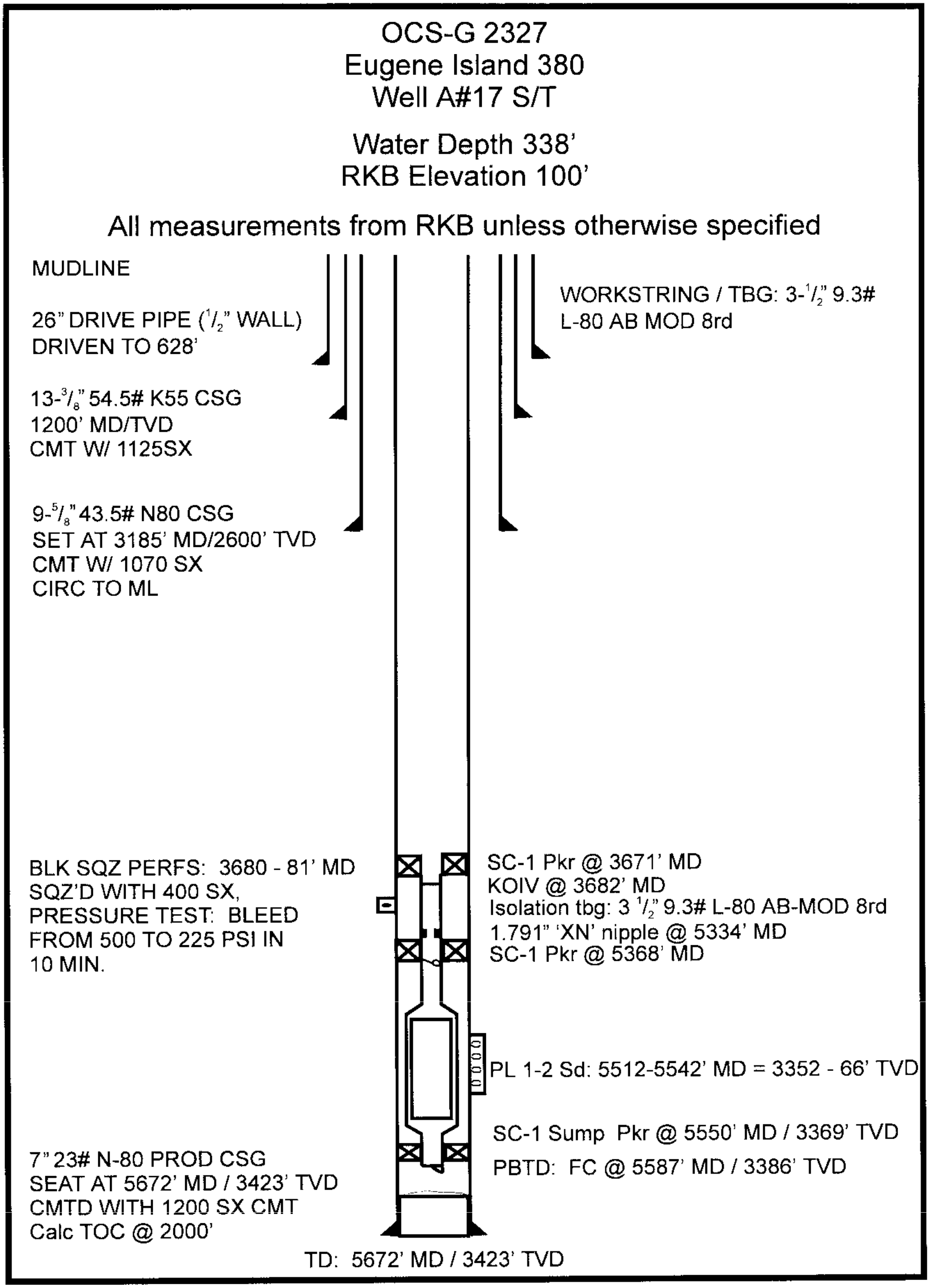
Location of Lease OCS-G 2327, Eugene Island Block 380

Attachment 3

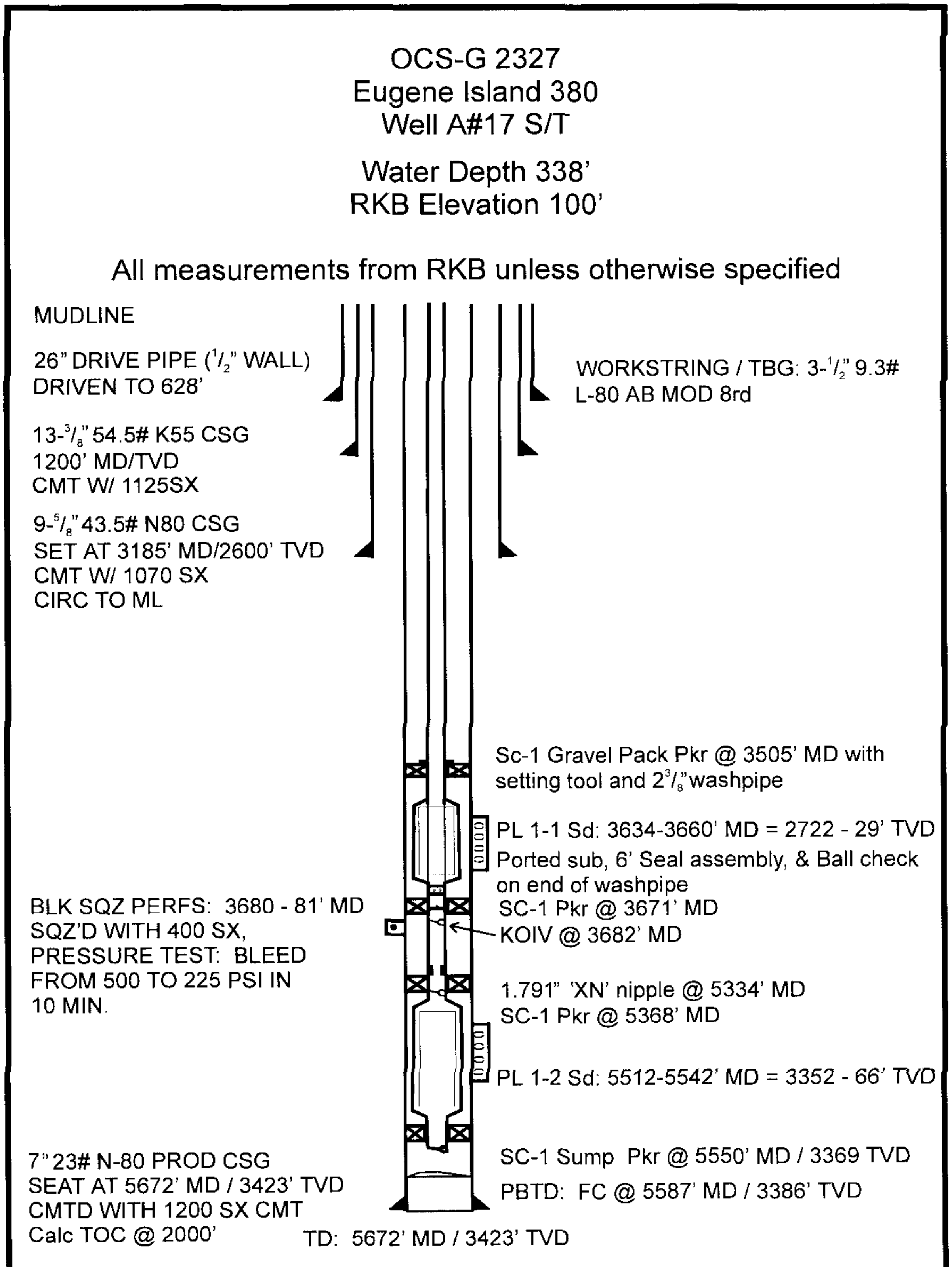


Schematic of PL 1-2 Sand Completion

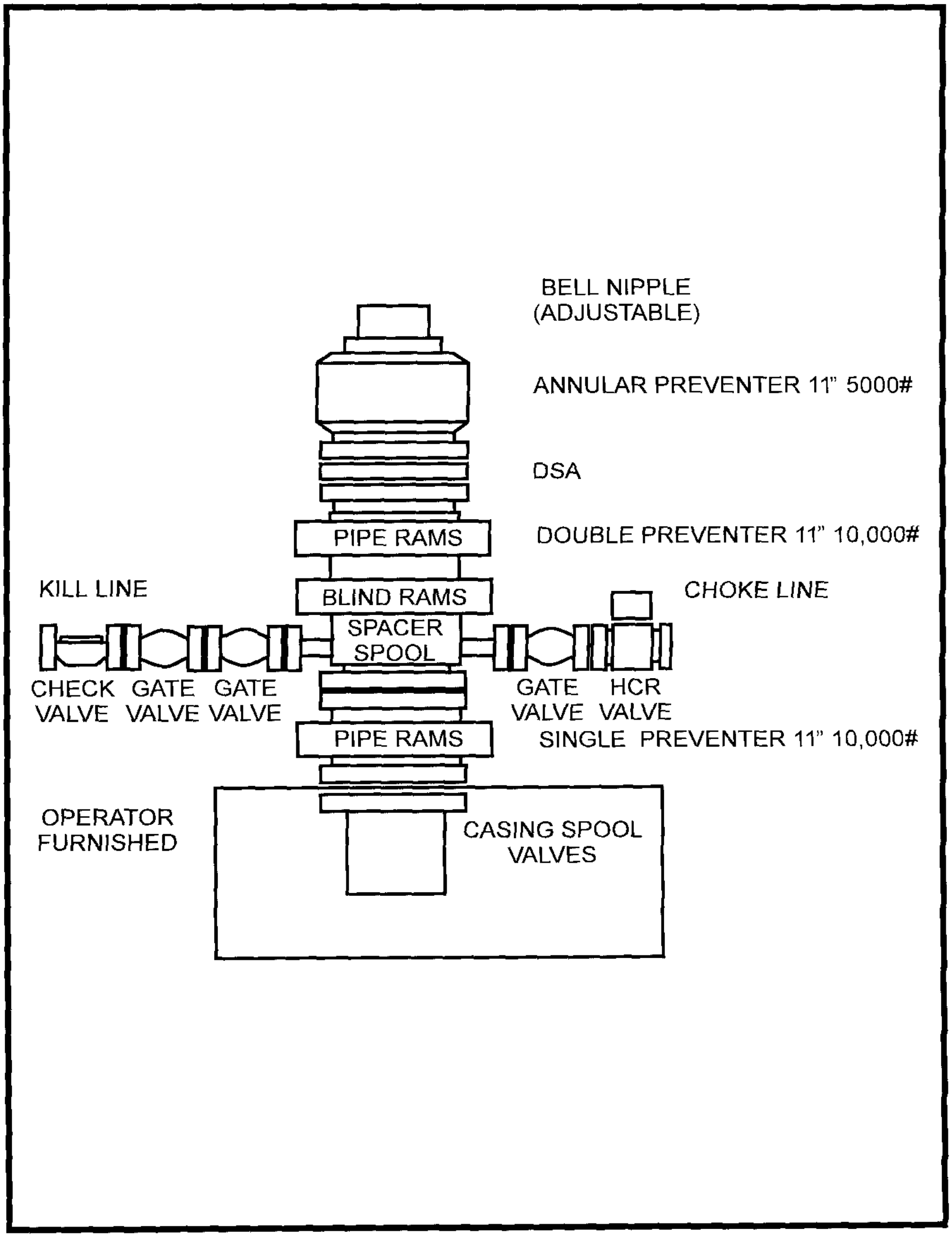
Attachment 4



Schematic of isolation and spacer phase above PL 1-2 Sand Completion

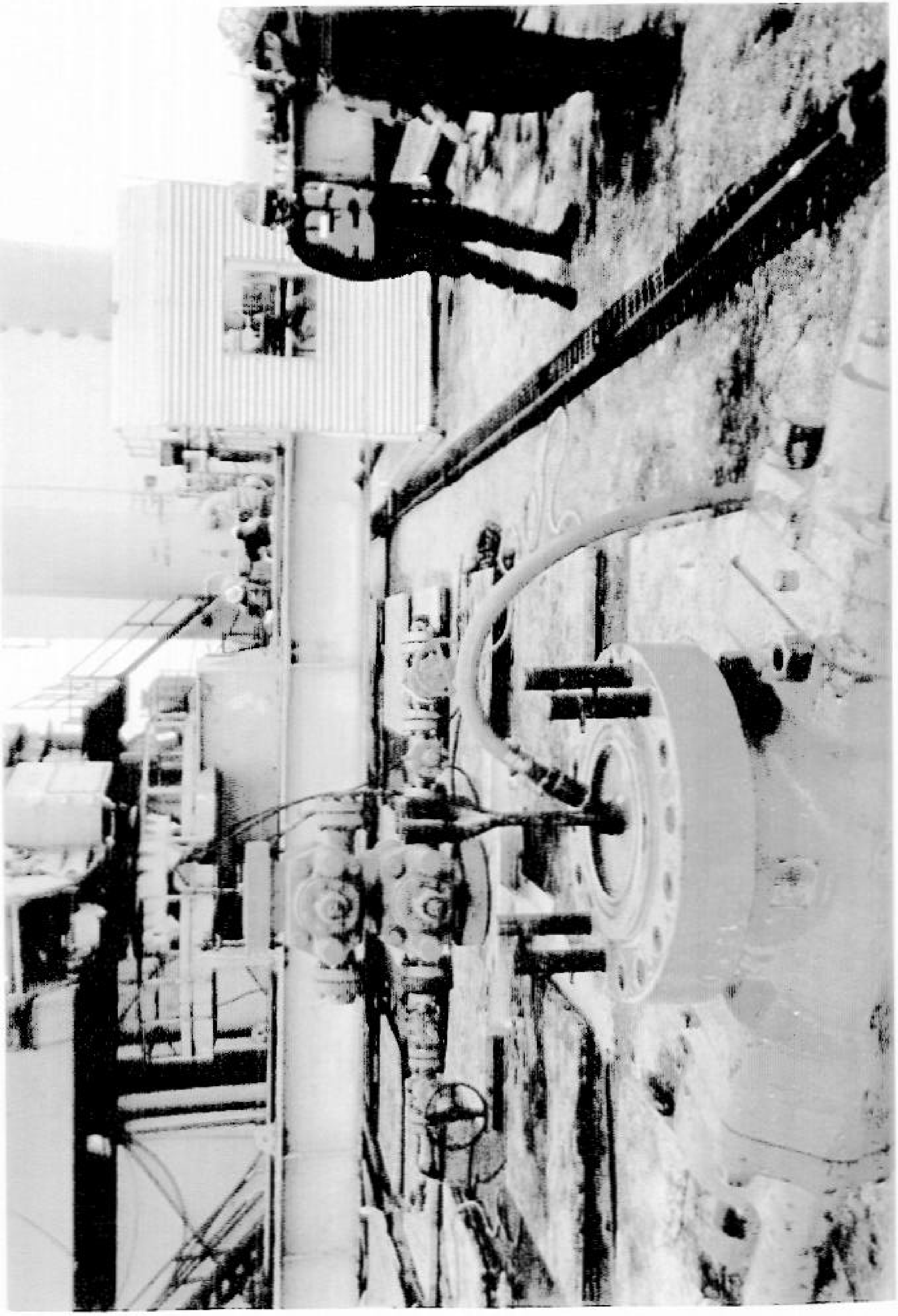


Schematic of PL 1-1 Sand Completion



Schematic of BOP Stack

Attachment 7



Photograph of Smashed Tubing.

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.