OCS Report
MMS 95-0041

Investigation of Loss of Well Control
Well B-2, South Marsh Island Block 90
Lease OCS-G 8684
March 15, 1994

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

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J.T. Gordon
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U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

New Orleans
July 1995

Contents

Investigation and Report

Authority

A serious accident occurred aboard Noble Drilling Inc.'s (Noble) jack-up rig *Percy Johns* during the conduct of workover operations for Exxon Corporation (Exxon) on Well B-2, in South Marsh Island Block 90, Lease OCS-G 8684 in the Gulf of Mexico, offshore the State of Louisiana, at approximately 7:00 a.m. on March 15, 1994. Pursuant to Section 208, Subsections 22(d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 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 March 15, 1994, the following MMS personnel were named to the investigative panel:

J.T. Gordon, Lafayette, Louisiana

C.J. Schoennagel, New Orleans, Louisiana

J.D. Serrette, Lafayette, Louisiana

The United States Coast Guard was represented on the joint investigative panel by Lt. Paul Albertson, Marine Safety Office, Morgan City, Louisiana.

Procedures

The accident occurred at approximately 7:00 a.m. on March 15, 1994. The MMS Lafayette District Office was notified later that morning and made plans to send the Lafayette District Drilling Engineer and an inspector to the rig. Due to inclement weather conditions, however, the Lafayette District personnel did not arrive on the rig until the morning of March 17, 1994. Upon arrival on the rig, the Lafayette District personnel proceeded to obtain information about the accident. The United States Coast Guard representative

had arrived on the rig March 15, 1994, and had also gathered information on the accident.

The joint investigative panel convened on April 25 and 26, 1994, at the MMS Regional Office in New Orleans, Louisiana. The following individuals were questioned about the accident and related activities:

Michael Downs, Noble Drilling Inc. employee

Bill Noland, Noble Drilling Inc. employee

Blaine Ewing, Noble Drilling Inc. employee

Perry Hammond, Noble Drilling Inc. employee

Tommy Goss, Noble Drilling Inc. employee

Jack Esterling, Noble Drilling Inc. employee

Max Smith, Noble Drilling Inc. employee

Hershell Aultman, Noble Drilling Inc. employee

Rodney Hebert, Noble Drilling Inc. employee

Jeff Foster, Noble Drilling Inc. employee

Floyd Avery, Sam Jones & Associates consultant

Michael Gremillion, Cooper Industries employee

Introduction

Background

Lease OCS-G 8684 covers approximately 5,000 acres and is located in the South Marsh Island Area Block 90, GOM, off the Louisiana coast. (For Lease location, see attachment 1.) The lease was issued effective July 1, 1987, for a cash bonus of $2,779,000. The original lessee was Tenneco Oil Company. Chevron U.S.A. Inc. was the lessee of record at the time of the accident.

On September 13, 1991, Chevron U.S.A. Inc. designated Exxon Corporation as the operator of the SW1/4 SW 1/4 and W1/2 SE1/4 SW1/4 of South Marsh Island Area Block 90. The bottomhole location of Well B-2 is within this described area. The surface location of Well B-2 is on South Marsh Island Area Block 99, Lease OCS-G 4109. The designated operator for South Marsh Island Area Block 99 at the time of the accident was Exxon Corporation.

An initial Development Operations Coordination Document (DOCD) for Well B-2 was submitted September 16, 1991, and approved November 14, 1991. On October 23, 1991, Exxon Corporation submitted an Application for Permit to Drill (APD) for Well No. 2 in the South Marsh Island Area Block 90. The APD was approved December 11, 1991. Well No. 2 was subsequently drilled and temporarily abandoned on May 25, 1992. A sundry notice to tieback and complete as well as change the well name from No. 2 to B-2 was submitted September 29, 1993, and approved October 7, 1993.

Well B-2 was completed on January 16, 1994, and rig operations on the well were suspended. The well was shut in until January 18, 1994, at which time the well was allowed to flow. The well demonstrated erratic flow behavior and subsequent wireline work indicated possible tubing damage. Several weeks of diagnostic work were performed to observe the well and monitor tubing/casing pressures.

Description of Accident

Noble Drilling Inc.'s jackup rig *Percy Johns* was skidded over Well B-2 on March 12, 1994. Calcium Bromide (CaBr) was bullheaded down the tubing to kill the well. A back-pressure valve was then set in the tubing hanger of Well B-2 and the wellhead was removed.

A blowout preventer (BOP) stack was then nippled up to Well B-2. While the back-pressure valve was being removed from the tubing hanger, an unexpected release of wellbore pressure occurred. The well was shut in almost immediately after the release of pressure by activation of one set of the pipe rams in the BOP stack.

One fatality and two injuries occurred as a result of the accident.

Findings

Preliminary Activities

On March 12, 1994, at approximately 8:00 a.m. the Noble jack-up drilling rig *Percy Johns* was skidded over Well B-2 to initiate workover activities. Well B-2 had a sustained casing pressure of approximately 800 psi on the tubing/casing annulus.

Steel lines were rigged up to the Well B-2 wellhead from the rig floor. A companion flange was nippled up to the wing valve and both were tested to a low of 250 psi and a high of 10,000 psi. A dual wing valve was nippled up on the C section of the tubinghead to allow for access to the tubing/casing annulus. The tubing/casing annulus was then bled down from 800 psi to 250 psi. Steel lines were then rigged up from the rig floor to the dual wing valve and tested to a low of 250 psi and a high of 3,000 psi.

The tubing/casing annulus was then filled with 4.5 barrels of 14.2 pound per gallon (ppg) Calcium Bromide (CaBr). The steel lines to the C section were rigged down and a needle valve and pressure gauge were installed to monitor the pressure on the tubing/casing annulus.

Removal of Wellhead

By approximately 5:00 p.m. on March 12, 1994, steel lines were nippled up to the wing valve on the Well B-2 wellhead and tested to a low of 250 psi and a high of 10,000 psi. At this time the pressure on the tubing/casing annulus was 250 psi.

The tubing was pressured up to 6,800 psi. The surface-controlled subsurface safety valve (SCSSV) was opened and the pump for the cementing was used to bullhead 120 barrels of 14.2 ppg CaBr down the tubing. This calculated to be +30 barrels of CaBr needed to fill the tubing and a 300-psi overbalance with formation pressure. The maximum injection pressure was 6,800 psi, while the maximum tubing/casing annulus pressure read at the C section was 775 psi.

After the well was killed, the SCSSV was closed by bleeding down the external control line pressure to the valve. The well was then monitored until it was determined that it was stable. This monitoring was conducted at the cementing unit from 7:30 p.m. to 10:00 p.m. Subsequent testing of the SCSSV at an onshore facility in Houma, Louisiana, indicated a minor leakage rate around the flapper when simulated pressures were applied both above and below the flapper.

At approximately 10:00 p.m. a Cooper Oil Tools (Cooper) service representative initiated installation of a back-pressure valve in the tubing hanger of Well B-2. This back-pressure valve is designed such that fluid can be pumped down it after it has been set in the tubing hanger.

Noble personnel and the Cooper representative testified that, as the crown valve at the top of the wellhead was opened, they heard and smelled gas venting from the well. At that time concerns were raised about the installation of the back-pressure valve under those conditions. Several discussions were held with Exxon representatives about these concerns, with the final decision

being to set the back-pressure valve in the tubing hanger. This operation was then completed using a dry rod without further incident at approximately 10:30 p.m. on March 12, 1994.

The next operation was the removal of the Well B-2 wellhead. Several attempts were made to pull the wellhead without success. The wellhead was finally pulled at approximately 12:00 noon on March 13, 1994. Some outer damage was noted on the tubing hanger as a result of a snap ring being out of place.

Loss of Well Control

Once the wellhead was removed, the next operation was to nipple up the blowout preventer (BOP) stack to Well B-2. The riser was picked up, the drill floor was skidded one foot to the port side, the riser and BOP stack were nippled up to the top of the tubing head, and the drill floor was skidded eight inches to the stern. (For schematic of riser and BOP stack, see attachment 2.)

All 10,000-psi valves on the choke manifold were tested to a low of 250 psi and a high of 10,000 psi. The 5,000-psi valves were tested to a low of 250 psi and a high of 5,000 psi. By 2:30 p.m. on March 14, 1994, the choke and kill lines were nippled up, the bell nipple was nippled up, and the final positioning of the rotary over the well was completed.

From 2:30 p.m. through 12:00 midnight on March 15, 1994, the remainder of the equipment on the drill floor, the BOP stack, and associated equipment

were pressure tested to the required low and high test pressures. There were no problems identified with these tests.

Between 12 midnight and 6:00 a.m., March 15, 1994, seawater was pumped from the BOP riser and tubing hanger. One to two feet of seawater was left in the tubing hanger.

During the same timeframe, 150-psi tubing/casing annulus pressure was indicated at the C section. Eight barrels of CaBr were lubricated into the well at a maximum injection pressure of 1,000 psi. The casing pressure was then bled down to 0 psi. The steel lines to the C section were rigged down. The makeup of a tubing hanger retrieving string was also initiated.

After several modifications, a tubing hanger retrieval string was made up and racked back in the derrick for use when the back-pressure valve was removed from the tubing hanger. The retrieving tool for the back-pressure valve was then made up on 2⅞-inch tubing.

At approximately 6:30 a.m. a Job Safety Analysis (JSA) meeting was held on the drill floor with Exxon, Noble, and Cooper personnel to be involved in the removal of the back-pressure valve. In this meeting personnel were assigned duties for this operation; in addition, the actions to be taken if pressure was encountered during the removal process were discussed.

After the meeting the Cooper representative began removal of the back-pressure valve by making approximately 360° turns with a pipe wrench on the tubing attached to the back-pressure valve removal tool, stopping periodically to check the status of the well. Testimony indicates that after the fifth 360° turn was made, the 1- to 2-foot level of seawater left in the tubing hanger disappeared, apparently draining into the well. Testimony conflicts as to whether very minor bubbles were observed in the seawater prior to its level disappearing. The observations of this seawater were being made by personnel looking approximately 70 feet down the riser using a flashlight. (For photograph view from drill floor, see attachment 3.)

After several 360° turns are made on the retrieval tubing, the back-pressure valve is designed to detect pressure below the valve through a relief groove that allows communication between the wellbore and the tubing hanger. (For schematic of back-pressure valve, see attachment 4.) Subsequent inspection of the back-pressure valve found the relief groove completely full of debris.

Two additional 360° turns were then made on the back-pressure valve retrieval tubing. This should have unseated the poppet from the profile, causing the pressure seal between the wellbore and the tubing hanger to be completely eliminated. This action should have allowed the wellbore to be open to the tubing hanger. However, this time no pressure was observed on the rig floor. Subsequent inspection of the back-pressure valve showed that the poppet was not free to move.

Four 360° turns were then made to break the back-pressure valve out of the tubing hanger. Testimony from the Cooper representative indicates that, as the fourth turn was completed, the tubing jumped, indicating that the back-pressure valve was unscrewed from the thread of the tubing hanger. Almost simultaneously with this, loss of well control occurred as pressure was released from the wellbore.

Restoring Well Control

The release of the pressure expelled fluids from the wellbore and apparently caused the tubing being used to remove the back-pressure valve to jump several feet into the air. The tubing was not blown out of the riser but was bent as a result of the incident.

The release of pressure also caused the rotary bushing inserts that were in the rotary table to be blown onto the drill floor. (For photographs of rotary bushing inserts, see attachment 5.) Testimony from personnel on the drill floor at the time of the accident indicates that no other significant damage to equipment was observed as a result of the pressure release.

Almost immediately after the loss of well control, a Noble employee stationed at the BOP control panel on the drill floor activated the upper set of variable bore pipe rams. This action shut in the well, stopping the release of pressure onto the drill floor.

Fatality and Injuries

An Exxon company representative, Larry Rohan, was found lying on the drill floor severely injured after the initial release of pressure from the wellbore. Larry Rohan was standing on the drill floor several feet away from the rotary table with other personnel just prior to the loss of well control. Testimony indicates that no one on the drill floor saw what happened to Larry Rohan, but it also indicates that one of the rotary bushing inserts was located on the drill floor next to where he was found lying after the incident occurred.

First aid was administered to Larry Rohan until a helicopter arrived to transport him to Our Lady of Lourdes Hospital in Lafayette, Louisiana. Larry Rohan was pronounced dead upon arrival at the hospital. Examination revealed that he was apparently struck in the chest.

The Cooper representative, Mike Gremillion, was injured as the force of the pressure release blew him into the pipe rack. A Noble employee, Blaine Ewing, was injured as fluid from the wellbore was blown in his face.

Subsequent Activities

After the initial shut-in of the well, the annular preventer was also closed. At approximately 7:00 a.m. on March 15, 1994, the shut-in pressure of the well was 200 psi, with that increasing to 280 psi by 11:30 a.m.

The control line hoses for the HCR valves, which were found to be crossed, were reversed. The pressure was then bled through the choke line to 0 psi. A JSA was then held to discuss the removal of the back-pressure valve and the retrieval tubing from the well. By approximately 6:00 p.m. the equipment

was removed from the well and the blind rams were then used to shut in the well. The back-pressure valve had some visible damage that occurred to it during the loss of well control. (For photograph of back-pressure valve, see attachment 3.)

Equipment to kill the well was then hooked up and tested. By midnight on March 16, 1994, the shut-in tubing pressure was 610 psi. A kill fluid of 14.2 ppg CaBr was then bullheaded down the tubing. By the completion of this operation, pressure in the tubing/casing annulus was 2,900 psi. The well was then shut in and the pressure in the tubing/casing annulus was bled off.

Conclusions

Probable Cause of Incident

The probable cause of the incident was the removal of the back-pressure valve with pressure trapped below it. After the well was killed and the SCSSV was closed, gas somehow migrated up the wellbore and became trapped under the back-pressure valve.

Possible Causes of Trapped Pressure

The following are possible causes of the trapped pressure below the back-pressure valve:

1. The failure to ensure that the well was killed prior to installation of the back-pressure valve. The valve was set with indications that a minor amount of gas was venting from the well. This could have also resulted from gas being entrained in the CaBr at the time the well was killed.

2. Gas from the formation could have migrated up the wellbore. If the hydrostatic head of the CaBr was reduced through fluid loss, gas from the formation could have entered the wellbore.

Contributing Causes

The following were contributing causes:

1. The leakage of the SCSSV. If the valve was leaking prior to the incident, it could have allowed gas to migrate past it and become trapped under the back-pressure valve.

2. The failure to attempt to pump into the well through the back-pressure valve prior to initiating its removal. If this were done the pressure trapped below the valve may have been detected prior to removal.

3. The failure to observe the pressure trapped below the back-pressure valve through the relief groove in the valve. Debris found in the relief groove may have prevented the pressure from being detected.

4. The failure to observe the pressure trapped below the back-pressure valve when the poppet was unseated from the profile. The poppet was found not free to move. This may have prevented the pressure from being detected.

5. The observations for the detection of pressure being done some 70 feet above the potential release point.

Probable Cause of Fatality

The probable cause of the fatality of Larry Rohan was injuries he received after being struck in the chest by something expelled from the wellbore during the initial release of trapped pressure. Although the matter is not conclusive, it appears that Larry Rohan was struck by the rotary bushing insert.

Recommendations

Safety Alerts

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

1. Lessees, drilling contractors, and other service personnel should ensure the well is killed before initiating installation and removal of a back-pressure valve.

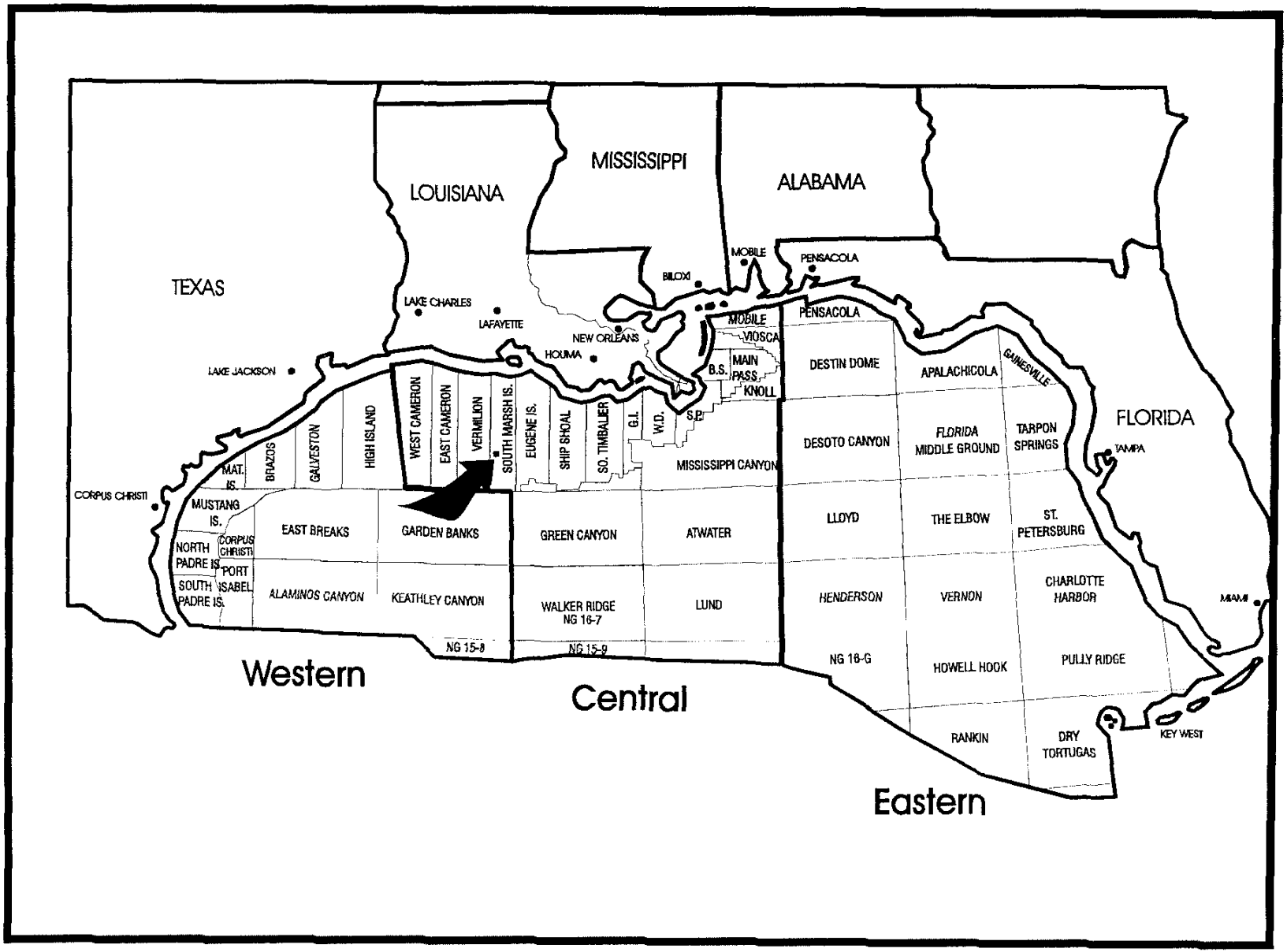
2. Lessees, drilling contractors, and other service personnel should ensure all equipment is functioning properly before initiating installation of a back-pressure valve.

3. Lessees, drilling contractors, and other service personnel should attempt to determine if pressure is trapped below a back-pressure valve before initiating removal of the valve.

4. Lessees, drilling contractors, and other service personnel should ensure that the rotary bushing inserts are locked down when inserted in the rotary table.

Regulatory Requirements

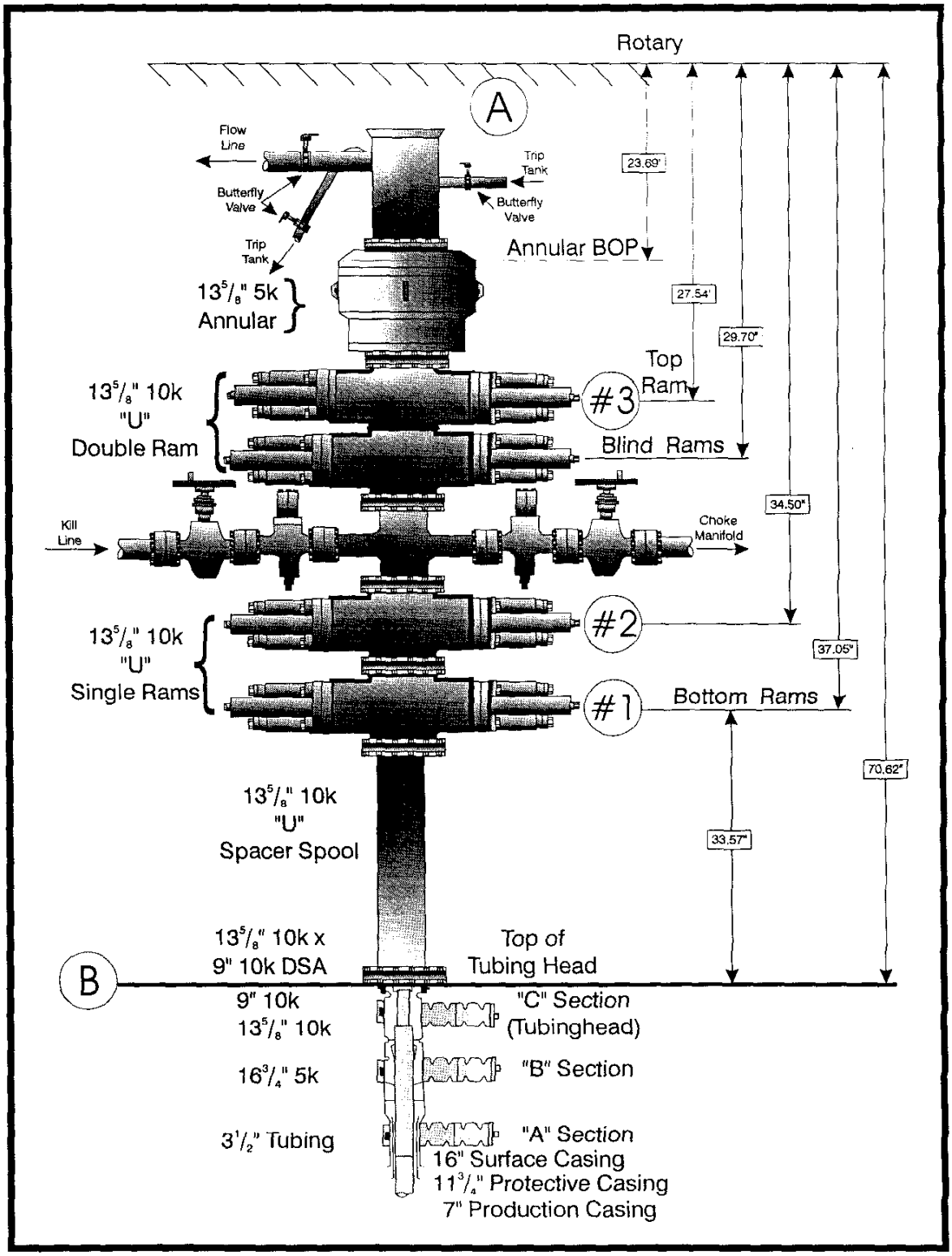
The MMS should require that the rotary bushing inserts be locked down when inserted in the rotary table.

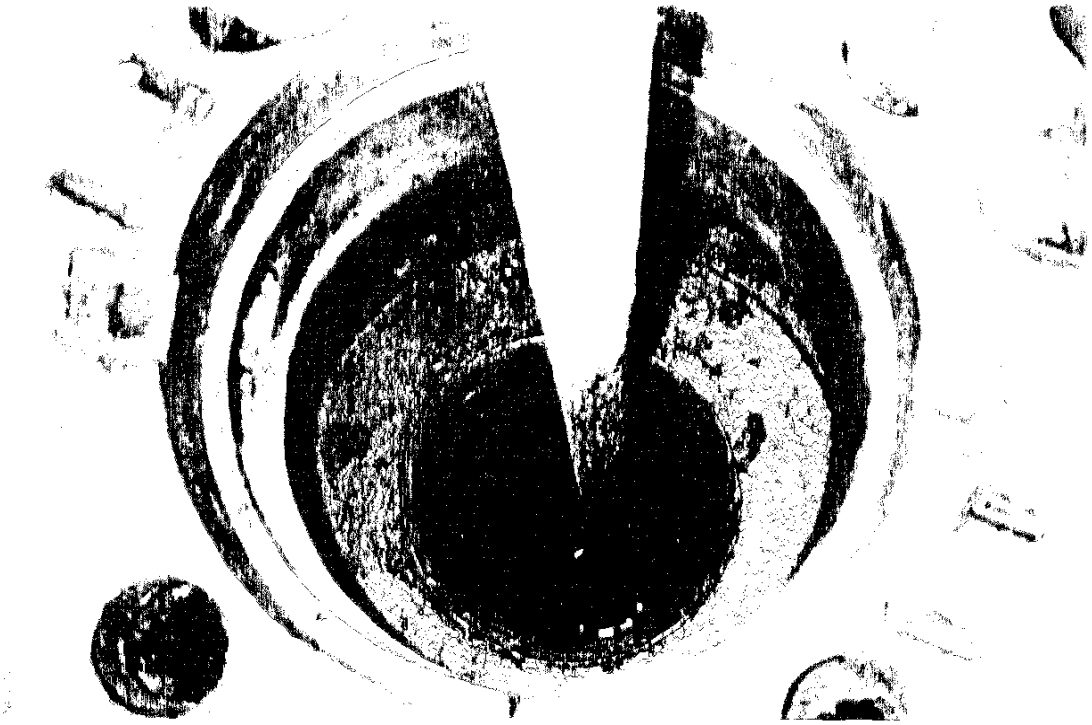


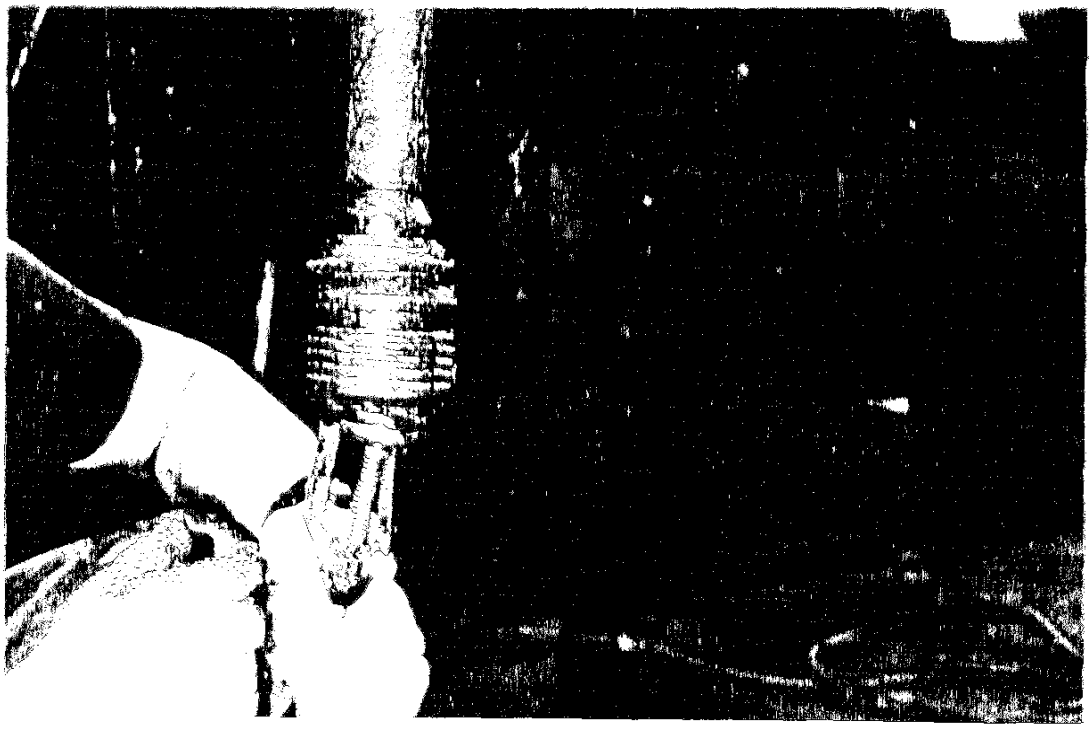
Attachment 1

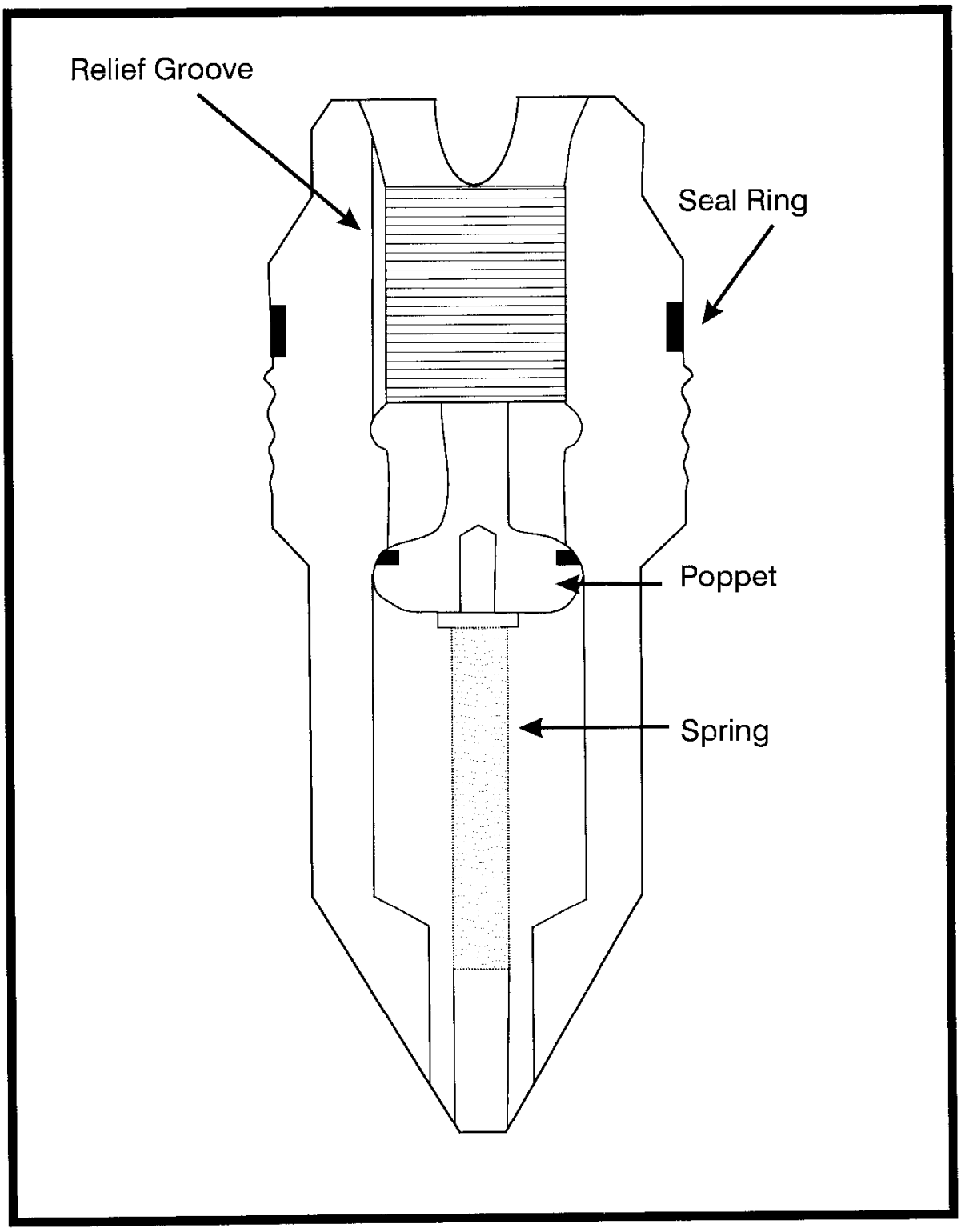
Location of Lease OCS-G 8684, South Marsh Island Block 90

Schematic of riser and BOP stack

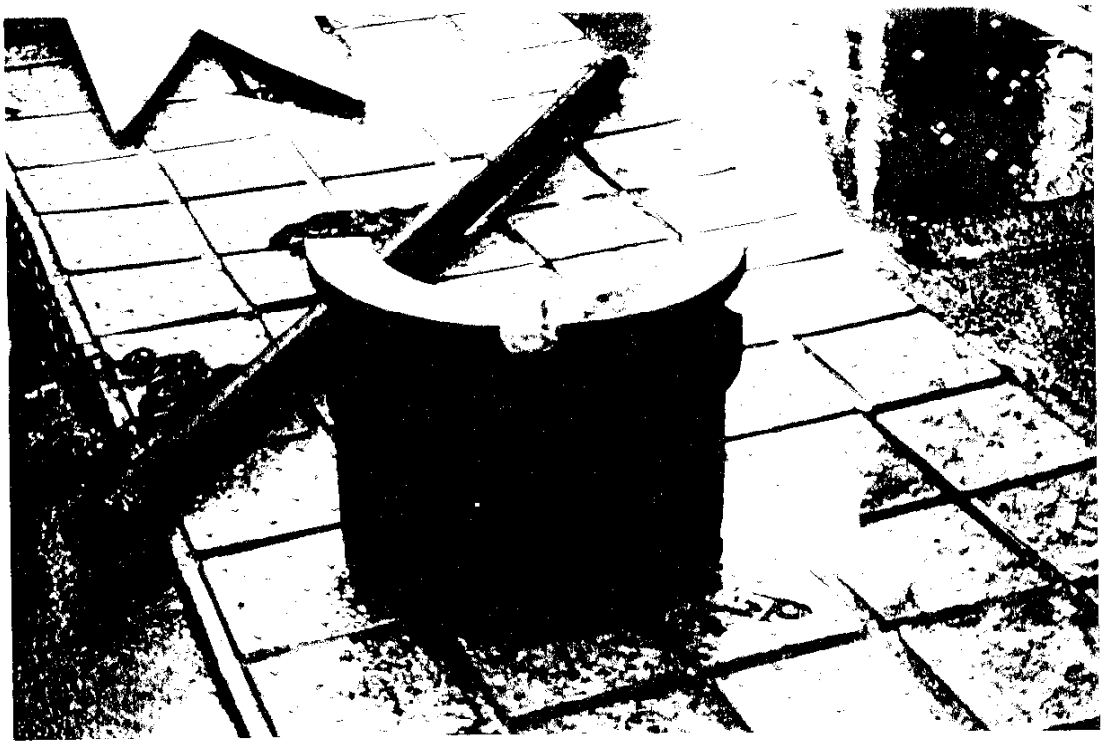




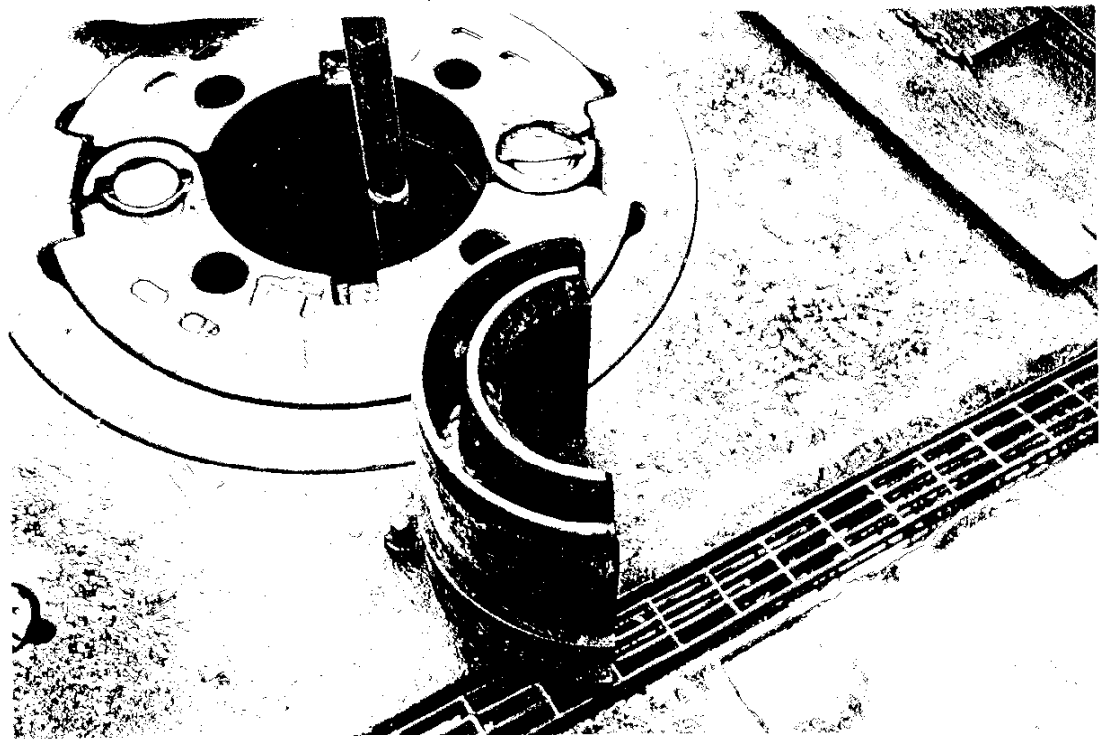




Schematic of back pressure valve



Photograph of rotary bushing insert



Photograph of rotary bushing insert

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.