UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
and
GEOLOGICAL SURVEY

INVESTIGATION OF OCTOBER 1982 BLOWOUT AND FIRE, EUGENE ISLAND BLOCK 361, GULF OF MEXICO

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OPEN-FILE REPORT 83-113

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This report has not been edited for comformity with Minerals Management Service and the U.S. Geological Survey publication standards.

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I. INVESTIGATION AND REPORT

A. Authority

A serious blowout and fire occurred on October 21, 1982, on Chevron U.S.A., Inc.'s (Chevron) "A" platform, Well A-10, Eugene Island Block 361, Lease OCS-G 2324, in the Gulf of Mexico, offshore the State of Louisiana. By memorandum dated October 25, 1982, pursuant to Section 208, Subsection 22(d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act Amendments of 1978, and Department of the Interior Regulation 30 CFR Part 250, the following Minerals Management Service (MMS) personnel were named as the Investigative Panel to investigate and prepare a public report:

Price McDonald, Reston, Virginia
W. H. Martin, Metairie, Louisiana
E. A. Marsh, Metairie, Louisiana
E. G. Hubble, Lafayette, Louisiana
D. F. Hrachovy, Lafayette, Louisiana

LCDR John S. Wenter, U.S. Coast Guard, was invited and participated in the questioning of witnesses.

B. Procedures

Informal hearings were convened in the conference room of MMS, Metairie, Louisiana, on October 26 and December 8, 1982. At each hearing, Chevron, the lease operator, and Noble Drilling Company (Noble), the drilling contractor, were represented by rig personnel on the platform when the accident occurred and by supervisory and staff personnel onshore who were connected with the drilling operation. In addition, at both hearings, Chevron and Noble attorneys were present as was the U.S. Coast Guard investigator. At the latter hearing only, two attorneys representing Hydril Company were present.

Questioning of witnesses by the Investigative Panel was informal. For the sequence of events prior to and immediately following the blowout, questions were directed to Chevron and Noble personnel who were on the platform and carrying out the drilling program. Where company practices and policies were tied in to these events, questions were directed to onshore office personnel. For the most part, questions in this latter category were answerable only by Chevron. (See the Appendix, List Nos. 1 and 2, for personnel in attendance at the two hearings.)

Certain valve equipment, known to be pertinent to the accident, was analyzed by the Investigative Panel (in part) at the locations as follows:

- Chevron's equipment yard, Harvey, Louisiana, November 17 and December 7, 1982.

- Valve actuator company's warehouse, Harahan, Louisiana, November 29, 1982.

Also, the ongoing operation and the platform facilities were viewed by the Investigative Panel (in part) at Platform "A", Eugene Island Block 361, December 2, 1982.

II. INTRODUCTION

A. Background

Lease OCS-G 2324, Eugene Island Block 361, South Addition, Gulf of Mexico, approximately 5,000 acres, some 90 miles off the central Louisiana coast, was issued February 1, 1973. (For the lease location, see the Appendix, Attachment No. 1.) It was purchased through a lease sale for $15,319,805.87. The original lessees were as follows:

Getty Oil Company	- 25 percent
Continental Oil Company (operator)	- 25 percent
Cities Service Oil Company	- 25 percent
Atlantic Richfield Company	- 25 percent

Effective May 1, 1979, Chevron U.S.A., Inc., acquired 70 percent of the interest in the lease and was designated as the operator. Ownership then became:

Chevron U.S.A., Inc. (operator)	- 70 percent
Conoco, Inc.	- 15 percent
Atlantic Richfield Company	- 15 percent

A Plan of Development to drill 14 wells from the "A" platform was submitted December 10, 1979, and approved on May 16, 1980. Application for Permit to Drill the A-10 Well was received in the Lafayette District on September 28, 1982, and approved on October 7, 1982. Total depth (TD) was to be 6500 feet, true vertical depth (TVD). (For the platform location, see Appendix, Attachment No. 2.)

Seven exploratory wells were drilled on the lease prior to commencement of drilling the wells off the "A" platform. Well No. 2, the nearest well to the platform, was drilled vertically at a location some 1,250 feet to the NNW. The surface locations of the other six exploratory wells ranged from 3,500 feet to 13,000 feet from the "A" platform location.

None of the seven exploratory wells experienced any shallow drilling gas-kick type incidents. Casing setting depths in all the wells were as required by OCS Order No. 2, and, in each case, a single conductor was run and cemented. Six of the exploratory wells were permanently plugged and abandoned, and one was temporarily abandoned. (For the exploratory well locations, numbers 1 through 7, and the platform well locations, A-1 through A-10, see the Appendix, Attachment No. 3.)

The shallow sands encountered in the drilling of the "A" platform wells were logged in five of the seven exploratory wells drilled.

Well A-1, the first platform well, was drilled through these sands without a serious incident; however, both gas-cut mud and loss of circulation problems were encountered. Due to significant accumulations of gumbo-type shale in the mud returns, extra care through short trips and mud conditioning was necessary in all wells in varying degrees to prevent swabbing by the drill bit. Wells A-1 through A-9 were drilled and cased before commencing Well A-10, except for Well A-3 which was abandoned when the 20-inch outside diameter (OD) casing parted while running. Well A-8 was perforated for completion and left in a shut-in status. Wells A-4, A-5, and A-9 were bottomed on the lease to the west, also operated by Chevron.

After cementing 18 5/8-inch OD casing at 950 feet in Well A-2, the release of gas appeared to be in evidence through gas bubbles at the surface. When this happened, Well A-1 was reentered, and squeeze-cement jobs were performed in several shallow gas sands.

In the platform wells drilled, shallow gas sands were most prominent as indicated above, with one sand being as shallow as 2100 feet. This degree and level of sand development was quite obvious in Well A-6 which was the closest borehole to Well A-10. Except for Well A-1, all platform wells were drilled with two conductors, the lower of which was set just above 2000 feet.

B. Description of Incident

On October 7, 1982, Noble's Rig 24 was skidded to the Well A-10 location, "A" platform, lease OCS-G 2324, Eugene Island Block 361, Gulf of Mexico. On the following day, 24-inch OD pipe was driven 227 feet into the seabed and set with the bottom at 653 feet below the kelly bushing (KB) datum. (Water depth was 305 feet.)

On October 9, 1982, the Well A-10 was spudded with the diverter manifold and annular preventer installed on the 24-inch OD drive pipe as shown in the Appendix, Attachment No. 4. The diverter line was flow tested by opening the diverter valve momentarily and allowing the mud returns to divert overboard. (One valve diverts to the outside when open; one diverts to the mud-gas separator when open.)

On October 12, 1982, 20-inch OD casing was set and cemented at 1295 feet, and on October 14, the well was kicked off directionally at 1615 feet approximately.

On October 15, 1982, 16-inch OD casing was set and cemented at 1919 feet measured depth (MD). On October 16, the valve to the diverter line to the outside was actuated again as a test. On October 17, closed diverter valves were pressured for 5 minutes from 650 pounds per square inch (psi) down to 450 psi while testing the casing shoe for bleed off.

After drilling a 12 1/4-inch hole directionally to 4292 feet MD (4018 feet TVD), the well was circulated for 2 to 3 hours with 10.7 pound per gallon (lb/gal) mud in preparation for tripping and logging. The gas units were measured as 60 which is not considered significant. While pulling the drill pipe up into the 16-inch OD casing as part of a short trip, the well was noted to be partially swabbing at about 2493 feet. With some difficulty, the next six stands were pumped out of the hole, picking up the kelly on each stand. After 45 minutes of circulating with the kelly connected, the gas count by the mud analyzer was up to 350 units. The reading dropped back to 100 units momentarily, and the well started flowing on the casing. This occurred about 1:30 a.m., October 21, 1982. The mud pit gain throughout this sequence of operations totalled about 50 barrels (bbl). (The well schematic is shown in the Appendix, Attachment No. 5.)

With this development, the rig crew was directed to start back in the hole with the drill pipe. One stand only was connected before increased flow forced a shut down, leaving the drill pipe with bit attached at 2010 feet. (The drill pipe was isolated internally by a drill pipe float valve previously installed above the bit.)

The kelly was again connected, and the annular preventer was closed. The returns were diverted through the gas-mud separator, with the degassed mud then going to the mud pit and the gas to a vent line off the separator. ((At the driller's control panel, a single lever was used to direct air pressure to open the diverter valve to the separator while simultaneously closing (or maintaining closure of) the diverter valve to vent the returns horizontally to the outside. Without adjustment, the single lever could be used to reverse the valves. With appropriate adjustments, the single lever could direct the air pressure to close or to open either of the diverter valves.))

When the returns increased and became more gaseous, the Chevron representative determined that the well should be vented to the atmosphere. Initial attempts for some 20 to 30 minutes to activate the diverter valves were unsuccessful because the pneumatic actuators on the valves failed to respond to remote lever action. Finally, after a union connection broke just downstream of the diverter valve to the separator, that particular diverter valve was closed successfully by pneumatic force. This left both diverter valves in a closed position and the well shut-in. The time was not yet 3:00 a.m. The total increase in the mud pit level was now up to 100 bbl approximately.

For the next 30 minutes or so, attempts continued to activate the diverter valve which would allow the well to vent overboard. Over the last few minutes, while still attempting to divert, a gauge was installed on the casing, and the pressure was read as 1000 psi.

Shortly afterwards, the annular preventer began leaking, and then it failed abruptly and loudly. At this point, well-control was lost. The time was about 3:30 a.m.

The general alarm was sounded, and by 4:00 a.m., the 42 persons aboard were off loaded via two Whitaker capsules without incident. Power was shut down, but about 1:20 p.m. of the same day, October 21, the well caught fire and burned until 9:30 a.m., October 24, 1982. It continued to flow but with less and less strength until about 6:00 a.m., October 28, 1982, when it bridged over. Increased water in the gas flow appeared to be the reason for the fire to diminish and eventually go out. (For photographs of the blowout and equipment damage, see the Appendix, Attachment Nos. 6 and 7.)

Damage to the rig and rig equipment, service equipment, and housing and galley facilities was extensive. Estimates from Chevron and Noble placed the total above $13 million.

Upon moving back on the well with a workover unit, a bridge was encountered at 1668 feet, and the hole was cleaned to 1700 feet. The drill pipe which dropped during the blowout and fire was not encountered. Noise and temperature logs were run as a check on fluid movement, and then two cement plugs were placed in the 16-inch OD casing. Temporary abondonment was completed on December 11, 1982.

III. FINDINGS

A. Preliminary Activities

Before commencing Well A-10, Chevron had drilled seven exploratory wells and eight platform wells through the same shallow-type gas sands which were encountered in and eventually blew out through Well A-10. The drilling experience had established the depths as below 2000 feet, the pressures as abnormal, and heaving or sloughing shale (gumbo) as a serious problem. When gas bubbles were noted following a conductor pipe cement job on Well A-2, the rig was skidded back to Well A-1, and several squeeze-cement jobs were completed in certain shallow sands to assure containment. Thereafter, the platform wells including Well A-2 were drilled with two conductor casings.

The diverter valves, as shown in the Appendix, Attachment No. 4, were installed as part of the control head on the 24-inch OD drive pipe on October 9, on the 20-inch OD conductor on October 13, and on the 16-inch OD conductor on October 16. On October 9 and again on October 16, the diverter valves were opened and closed to assure operation. On October 17, the diverter valves, while in a closed position, were subjected to 650 psi pressure as part of a 5-minute bleed off test of the casing shoe. However, on October 21 when the Chevron representative decided to switch the returns from a gas-mud separator direction to a horizontal vent direction, the valves would not operate. After several minutes, one valve was made to function.

Both the 20-inch and 16-inch OD casings were run without incident, but in each case, the cement job was questionable. With the 20-inch OD casing at 1295 feet, cement channeling became apparent when cement returns were noted very early. With the 16-inch OD casing at 1919 feet MD, the cement was inadvertently overdisplaced while pumping down with rig pumps. Upon drilling out and pressure testing the shoe over a 5-minute period, the pressure leaked off from 650 psi to 450 psi with 9.4 lb/gal mud in the hole. This was considered a satisfactory casing shoe test, and drilling proceeded.

Heaving shale (gumbo) was known to be a problem, so a conveyor belt was used as standard equipment to convey the gumbo overboard once separated from mud returns. True to previous experience, as drilling progressed in Well A-10, gumbo problems increased. On October 18, when the hole became packed, pipe movement, pumping, and short trips were necessary to stabilize the hole. Again on October 19, with the mud weight up to 11.0 lb/gal at times, gumbo and sand in the returns were cause for swabbing and alternatively lost-returns and well-flow situations. At 4093 feet, some 50 bbl of mud was lost to the formation. On October 20, the same type lost-returns and well-flow problems continued.

Contributing to the swabbing problem when tripping was the rapid buildup of the drilling angle just below the 16-inch OD casing at 1919 feet MD. At 1884 feet, the angle was 16°, and at 2074 feet, the angle was 27 1/2°. Rig personnel agreed that more caution was necessary in the 2000-feet to 2100-feet range than at deeper depths.

B. Loss of Well-Control

Drilling was slowed and made complicated by the unusually severe heaving shale (gumbo) conditions. Over the range of 2125 feet to 4292 feet, only one bit was required as against 3 days of time. Short trips were the rule rather than the exception in getting the hole to stand without fluid loss or gain. In conjunction with these trips, staging in and pumping out was necessary to maintain a balanced hole condition and avoid formation breakdown or swabbing.

After drilling to 4093 feet MD, a short trip into the casing at 1919 feet MD was completed. It required over 12 hours' time. With 11.0 lb/gal mud, returns were lost at 2052 feet going in, and several hours were spent adding lost circulation materials and reducing the mud weight to 10.5 lb/gal. After drilling to 4292 feet MD, another short trip was begun. At 2493 feet, swabbing was noted, and the next six stands were pulled slowly and pumped out to minimize the swabbing effect and keep the hole full. Even so, after circulating another 45 minutes, the well was observed to be flowing, and the pit gain was estimated to be 50 bbl.

To conserve mud as the gas flow picked up, the well returns were diverted through the mud-gas separator. This was done by closing the annular preventer and operating a remote control lever which pneumatically caused the diverter valve to the separator to open while holding the other diverter valve closed. Without further control over the formation influx, the gas in the returns increased, and the gas and gumbo became more serious as was apparent through noise and vibration. As the tempo gained, the diverter control was actuated repeatedly to direct the flow to the outside through the diverter manifold. The pneumatic actuators on the two valves would not function, and finally, a union connection broke just downstream of the separator diverter valve. Apparently, gumbo caused the line to plug and to allow pressure to build up. Further efforts to operate the diverter valves were half successful. The diverter valve to the separator was closed, but the diverter valve to vent the well horizontally could not be opened. This left the well bottled up. With the pressure reading about 1000 psi, the annular preventer failed, and any semblance of well-control was lost. (For photographs of the diverter valves and actuators following the blowout, see the Appendix, Attachments Nos. 8 and 9.)

The 8-inch ball-type diverter valves, rated at a working pressure of 2160 psi and actuated pneumatically, had worked under lesser pressures than 450 psi after testing the casing shoe. Upon examination following the blowout, no clue could be found to trace the malfunction. When the air was connected to the actuator, nothing happened because the seal within the actuator in each case would not hold pressure. Having been subjected to rather high temperatures during the blowout and fire, failure of the seals was not surprising.

The annular preventer was designed with a rated 2000 psi working pressure. It was actuated during drills on October 14 and 15. It was not purposely pressure tested while on Well A-10 since its use in the diverter manifold was to assure diversion of the well flow, not containment.

The Chevron decision to divert initially to the mud-gas separator rather than to the outside line was not in accord with their posting on the rig floor. The posting does not mention the separator nor does it mention saving mud (see Appendix, Attachment No. 10).

C. <u>Attempts at Restoring Well-Control</u>

At 1:30 a.m., when well flow on the casing became obvious, the Chevron representative believed the well might be brought under control by continued circulation and treatment of the mud. With the kelly connected and the annular preventer closed, the pumps were engaged, and the returns were diverted through the 8-inch diverter valve to the gas-mud separator. After 30 minutes or so, increased gas and chunky gumbo in the returns made well-control unlikely.

At this point, rig personnel found that the pneumatic actuators on the two diverter valves would not operate the valves as intended;

that is, lever action from the rig floor would not reverse the valve positions and allow the well to vent itself horizontally away from the rig. Efforts to operate the valves continued for another 20 to 30 minutes before the pressure mounted in the 6-inch line to the gas-mud separator and caused it to rupture. Most likely, the line became plugged with gumbo (see the Appendix, Attachment No. 8).

With the well essentially out of control, renewed emphasis was placed on finding a way to operate the diverter valves. With continued control adjustments, the actuator to the open diverter valve was found workable but not the actuator to the closed diverter valve. Without an alternative, the open valve was closed, and the closed valve was left closed leaving the well effectively shut-in.

For the next 30 minutes or so, as pressure increased at the surface, efforts continued to open the diverter valve which would direct the well flow away from the rig. When the annular preventer failed at 1000 psi, all hope for any semblance of well-control through diversion was lost.

Upon further analysis of the valve apparatus in Chevron's equipment yard, a Panel member noted that the 3/8-inch stainless steel line in the valve actuator manifold was bent, suggesting the possibility that insufficient air pressure was reaching the actuator to the open valve. However, when the bending took place, before or after the blowout, could not be determined.

D. Blowout and Fire

Well-control was lost about 3:30 a.m., October 21, 1982, and a full-scale gas blowout was immediately apparent. The gas flow was charged by one or more shallow gas sands with slightly abnormal pressures. The flow was outside the drill pipe and upward through the annular preventer.

All power was shut down preliminary to platform abandonment. Most likely this was a factor in the well not catching fire until shortly after noon (1:20 p.m.). No solid explanation can be given over how ignition started.

E. Emergency Warning and Evacuation

The general alarm was sounded about 3:30 a.m. when the annular preventer failed. All of the 42 persons aboard reported to the two Whitaker capsules and were lowered to the water safely. They were then motored via the capsules to another rig about a mile away.

F. Damage

The blowout and fire caused extensive equipment damage, but no lives were lost, no one was injured, and no oil polluted the water. The damage was estimated to be over $13 million. Included in the estimate were the drilling derrick, drawworks, pumps, engines, service equipment, structural repairs to the upper deck, wellhead equipment, living quarters and galley, and miscellaneous supplies.

IV. CONCLUSIONS

A. Proximate Cause of Incident

1. The well was swabbed while making a short trip up into the casing preliminary to logging, underreaming, and running surface pipe.

2. When well flow began and diverting of flow became necessary, the diverter valve to the mud-gas separator was opened purposely rather than the diverter valve to the vent line. This was done to conserve mud while circulating, hoping that the flow could be controlled.

3. Thereafter, the actuators to the diverter valves did not work properly, and the valve to divert horizontally was left closed throughout the ordeal. Why the valves would not work was not determined.

4. Finally, with the well closed in by the annular preventer, the two diverter valves, and the drill pipe float, the seal of the annular preventer failed with 1000 psi pressure.

B. Proximate Cause of Fire

The gas flow was vertical through the annular preventer and on up through the rotary table. All power was off. The gas did not ignite until some 10 hours after the blowout began.

No evidence was available to suggest how the well caught fire. Presumably, as the well cleaned up and the gas flow became wilder and stronger, sand began to flow too, and the abrasive action resulting at the surface caused ignition.

C. Contributing Causes to the Incident

1. The heaving shale (gumbo) was severe throughout the 2373 feet of open hole below the second conductor casing. It was so concentrated that short trips, staging in, and pumping out were commonly used to maintain hole stability. Although the low solids lime-base mud seemed adequate, the gumbo repeatedly packed the hole and led to lost circulation or well flow. Upon starting the last short trip, the drilling report read, "Does not appear to be getting proper amount of gumbo cuttings out of hole."

2. By correlation with other platform wells, Well A-10 was known to have penetrated multiple gas sands. One or more of these sands was a factor along with the gumbo in causing hole instability through gas-cut mud and lost circulation almost continually during the preceding 3 days.

3. A pronounced directional buildup in the depth range of 2000 feet to 2100 feet further complicated trips, hole stability, and the tendency to swab. Through this range, the severity was about 6°/100 feet. On the last day, swabbing became apparent at about 2493 feet and continued upwards for over 500 feet.

V. RECOMMENDATIONS

A. OCS Order No. 2 Be Revised

1. All annular preventers used in OCS operations shall be pressure tested in the plant or shop in accordance with American Petroleum Institute Specification for Wellhead Equipment (API Spec 6A), January 1981, Paragraph 5.3.7, Closed Preventer Test. This applies to new and to repaired and reconditioned annular preventers. With the latter, the organization performing the test shall provide certification papers, and such papers shall be made available to the District Supervisor upon request.

2. Small power lines, whether pneumatic or hydraulic, making up the actuator manifold from the control lever to the diverter valves coming off the blowout preventer stack shall be protected either by covering or enclosing or by attaching to a fixed object such as a beam.

3. If drilling in a diverting mode, the operator shall divert to the outside through a diverter line (rather than to a separator) when a blowout occurs or when well flow suggests an uncontrolled flow. A diverting mode includes those drilling conditions where the operator is drilling at shallow depths with a diverter system in place and without positive assurance of casing integrity.

B. Safety Alert Be Issued

1. A diverter manifold, when installed with an annular preventer for shallow drilling, should not be used for purposes other than diverting to the outside when well flow commences.

2. Where shallow gas sands are present and two conductor casings are run, a conventional blowout preventer arrangement may be preferable over a diverter setup. Such would be the case when the lower conductor has sufficient integrity to contain the flow if a blowout occurs.

3. Diverter valves and controls, whether pneumatic, mechanical, or hydraulic, should be installed with appropriate protection to avoid damage which might jeopardize momentary use. Also, the usual large-diameter diverter valve should not be opened and closed as a choke valve under pressure.

4. With gumbo conditions, the drilling mud must have sufficient viscosity, and annular velocities must be high enough to sweep the annulus and keep the hole clean. This means proper treatment of the mud and high-powered, high-volume pumps. With this combination, hole problems with gumbo can be tolerated and sometimes can be lessened.

List No. 1
Personnel in Attendance at First Informal Hearing
October 26, 1982

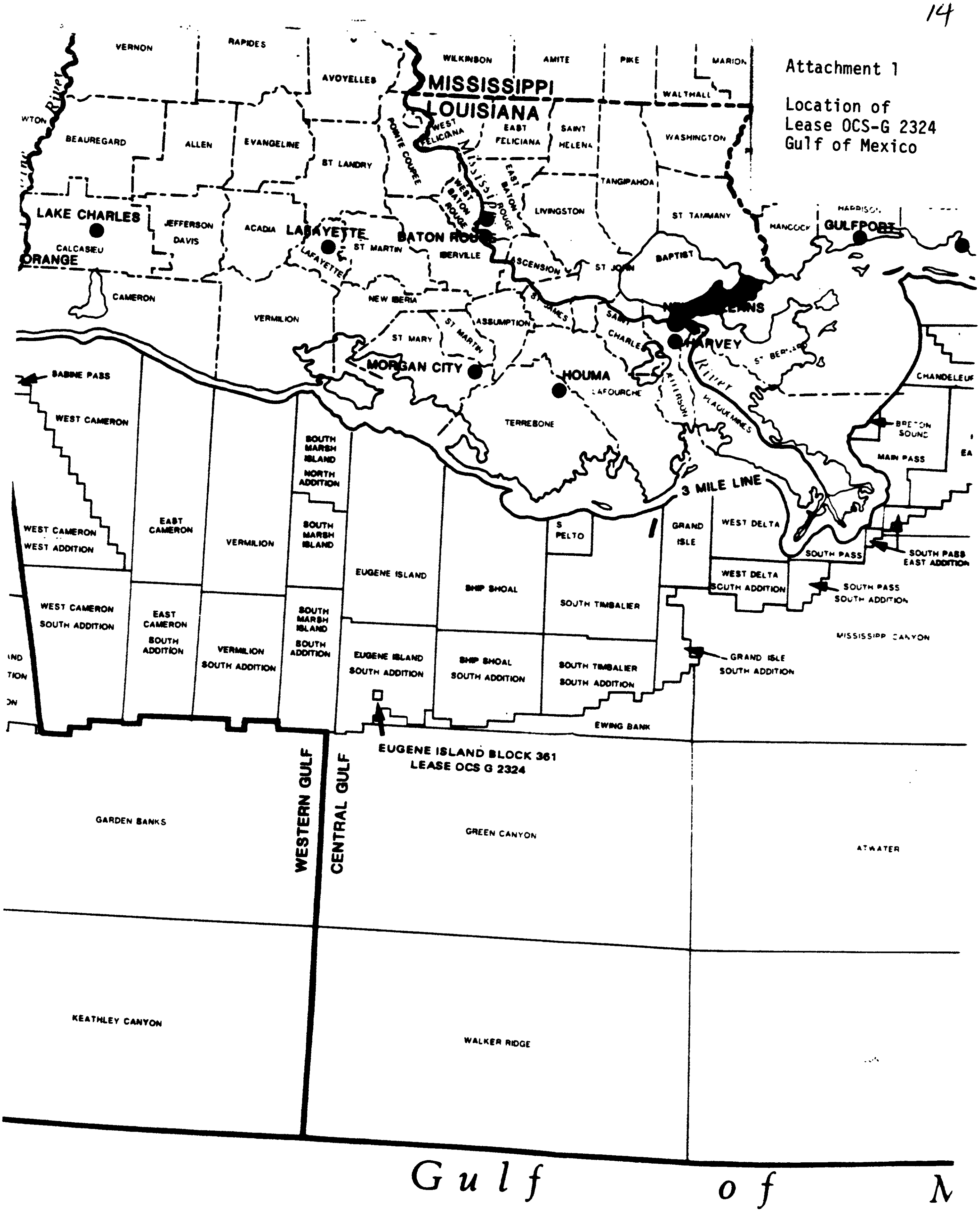
NAME	ORGANIZATION	POSITION
Price McDonald	Minerals Management Service - Reston	Division Chief
Bill Cotton	Chevron U.S.A., Inc.	Senior Staff Drilling Engineer
R. C. Fiore	Chevron U.S.A., Inc.	Associate Regional Counsel
Scott Drawe	Chevron U.S.A., Inc.	Drilling Representative
Max Peters	Chevron U.S.A., Inc.	Drilling Representative
C. R. Moak	Chevron U.S.A., Inc.	Drilling Representative
Paul G. Hyatt	Chevron U.S.A., Inc.	Drilling Representative
Elmo Hubble	Minerals Management Service - Lafayette	District Supervisor
John S. Wenter	U.S. Coast Guard	Investigation Officer
Dan Hrachovy	Minerals Management Service - Lafayette	Drilling Engineer
Eugene A. Marsh	Minerals Management Service - Metairie	Senior Staff Assistant Manager
Jimmy C. Walker	Noble Drilling Company	Drilling Superintendent
Ledry Richie	Noble Drilling Company	Tool Pusher
Aubry Rimes	Noble Drilling Company	Driller
Gus Andproes, Jr.	Noble Drilling Company	Division Drilling Superintendent
Lewis Dugger	Noble Drilling Company	Safety Supervisor
Tom Wyllie	Adams and Reese	Noble Attorney
Tom Willoughby	Chevron U.S.A., Inc.	Division Drilling Manager
Bill Martin	Minerals Management Service - Metairie	Senior Staff Advisor

List No. 2
Personnel in Attendance at Second Informal Hearing
December 8, 1982

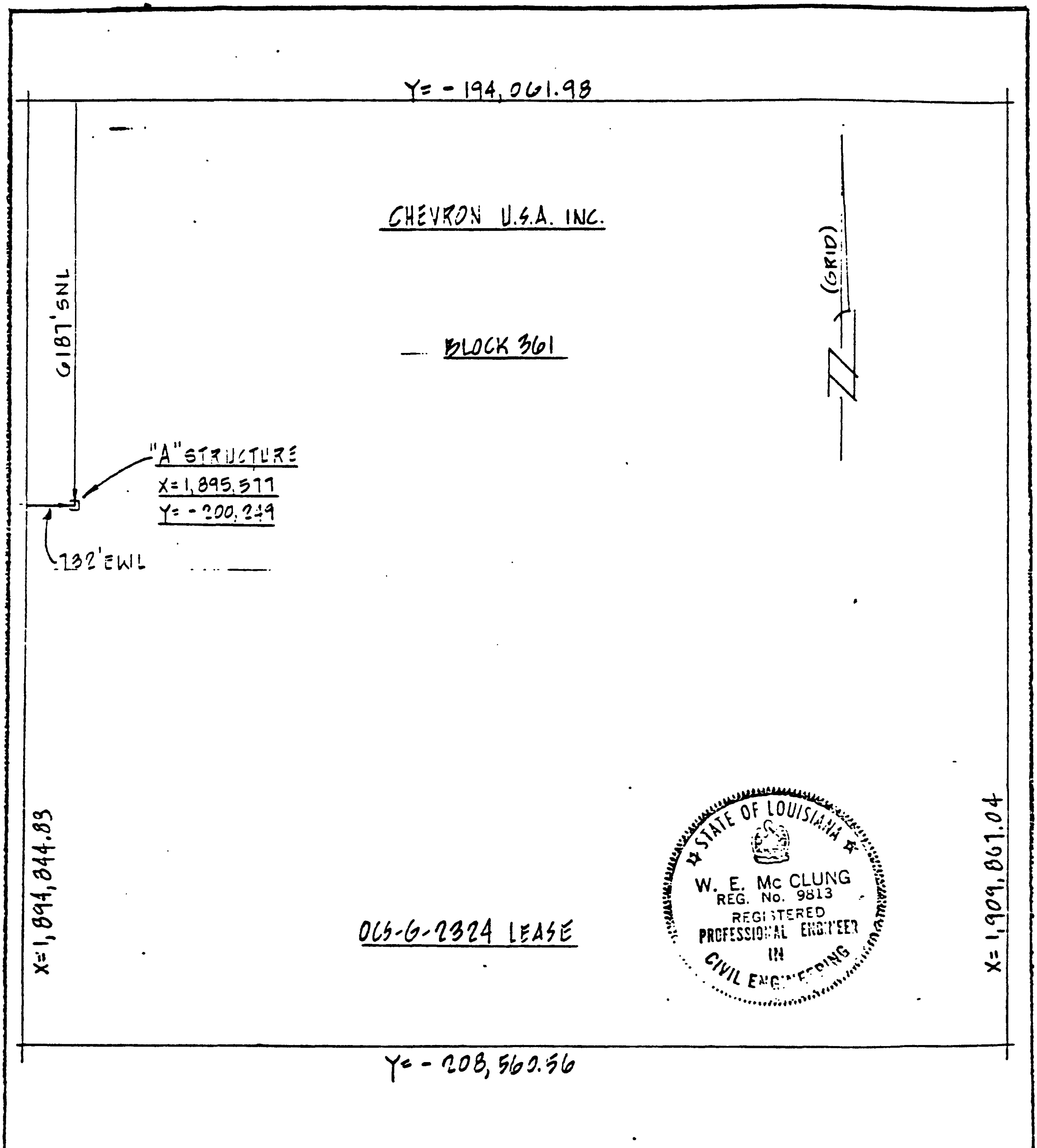
NAME	ORGANIZATION	POSITION
Price McDonald	Minerals Management Service - Reston	Division Chief
Bill Martin	Minerals Management Service - Metairie	Senior Staff Advisor
Elmo Hubble	Minerals Management Service - Lafayette	District Supervisor
Dan Hrachovy	Minerals Management Service - Lafayette	Drilling Engineer
Eugene A. Marsh	Minerals Management Service - Metairie	Senior Staff Assistant Manager
Tom Willoughby	Chevron U.S.A., Inc.	Division Drilling Manager
R. C. Fiore	Chevron U.S.A., Inc.	Associate Regional Counsel
C. R. Moak	Chevron U.S.A., Inc.	Drilling Representative
Paul G. Hyatt	Chevron U.S.A., Inc.	Drilling Representative
Lewis Dugger	Noble Drilling Company	Safety Supervisor
Tom Wyllie	Adams and Reese	Noble Attorney
Gus Androes, Jr.	Noble Drilling Company	Division Drilling Superintendent
Max Peters	Chevron U.S.A., Inc.	Drilling Representative
Alan Zaunbrecker	Adams and Reese	Noble Attorney
John Wenter	U.S. Coast Guard	Investigator
Jimmy C. Walker	Noble Drilling Company	Drilling Superintendent
Ledry Richie	Noble Drilling Company	Tool Pusher
Aubry Rimes	Noble Drilling Company	Driller
Scott Silbert	Barham and Churchill	Hydril Attorney
E. S. Elchin	Barham and Churchill	Hydril Attorney
Scott Drawe	Chevron U.S.A., Inc.	Drilling Representative
John Rankin	Minerals Management Service - Metairie	Regional Manager

Attachment 1

Location of
Lease OCS-G 2324
Gulf of Mexico



Location of "A" Platform
on Lease OCS-G2324, Gulf of Mexico

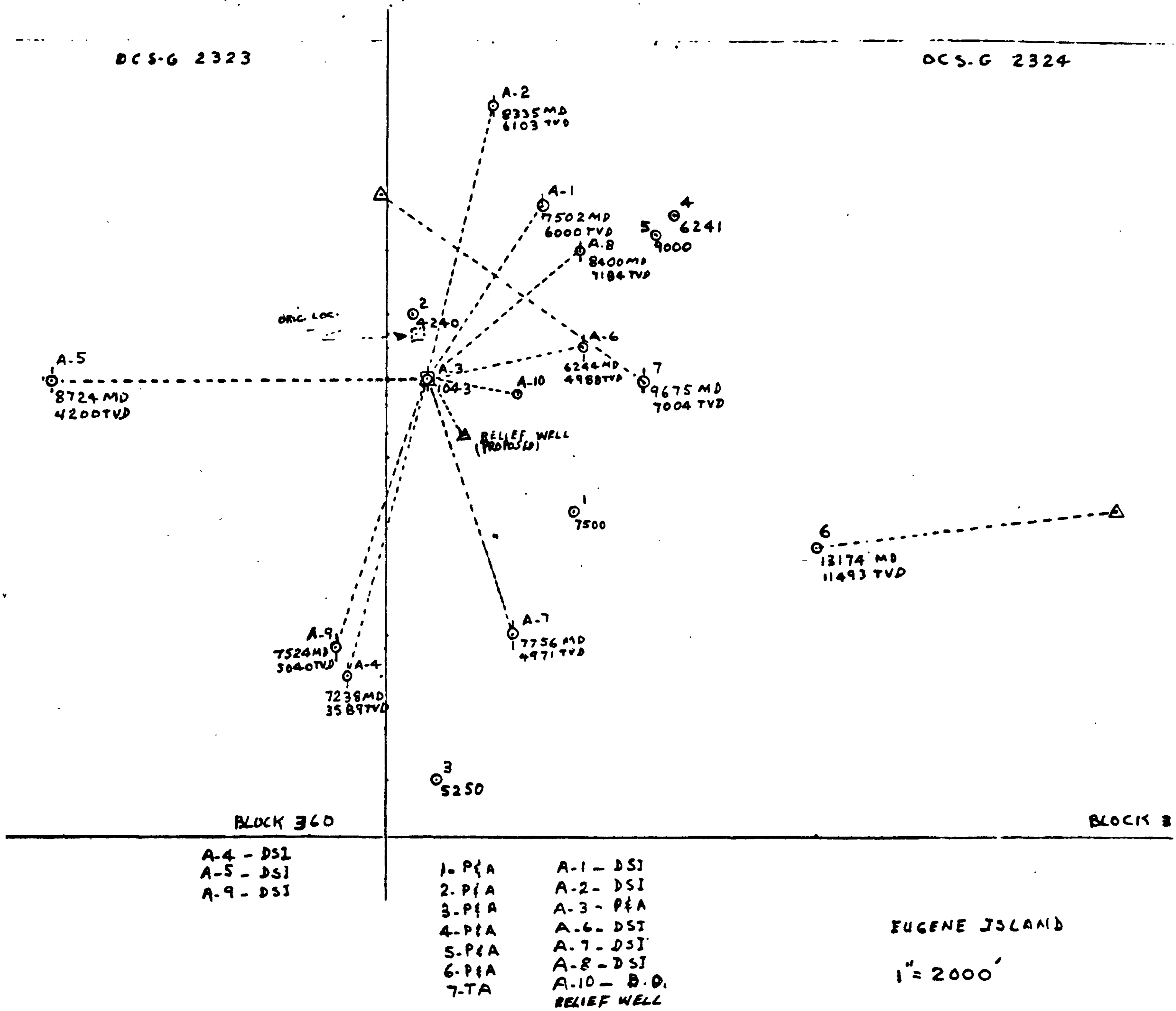


LOCATION PLAT
"A" STRUCTURE
EUGENE ISLAND BLK. 361 OCS-G-2324 LEASE

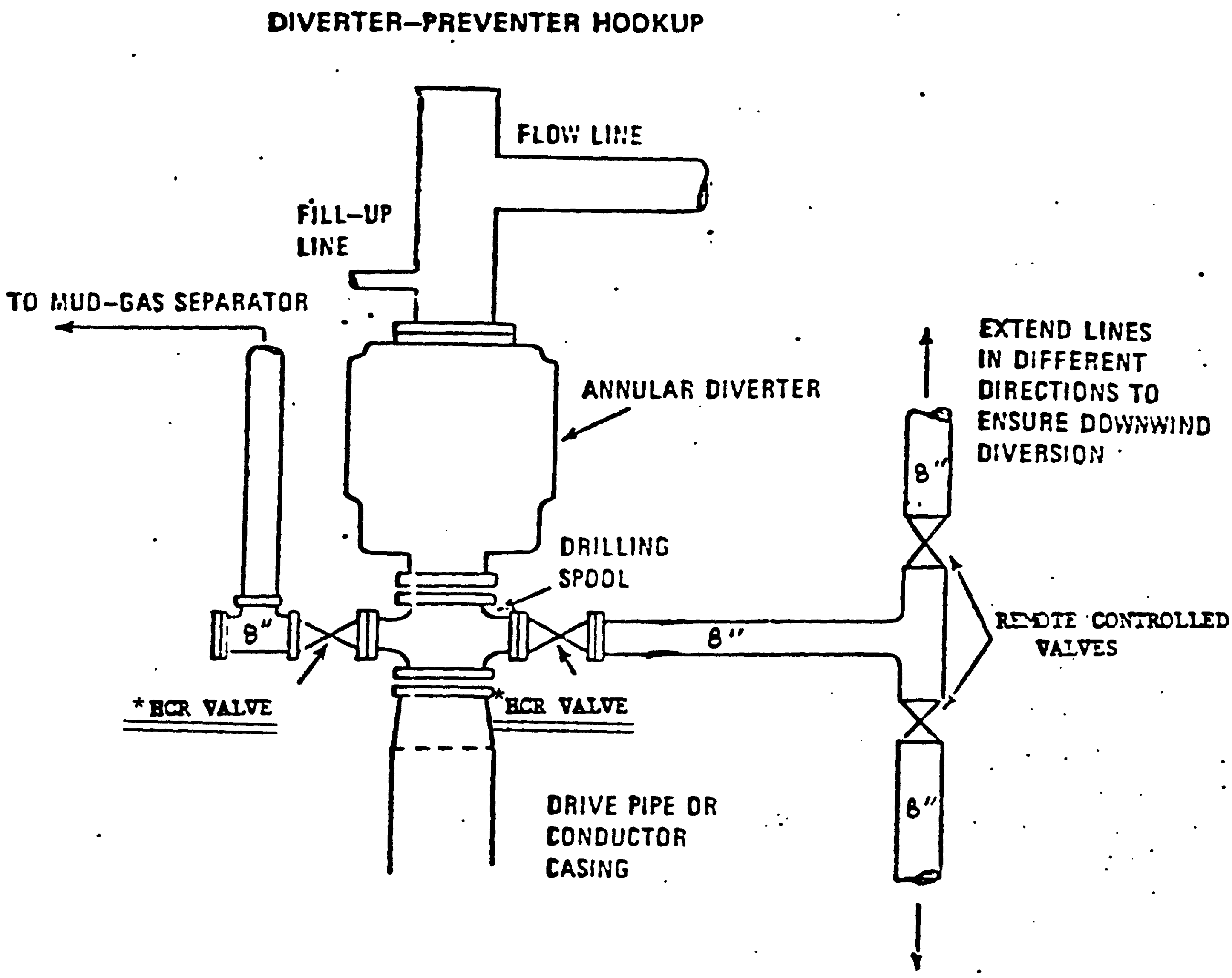
Chevron U.S.A. Inc.
P.O. Box 51743, Lafayette, LA 70505

Scale 1" = 2000' | Dwg. No.
25 MAY 1981 | JE

Exploratory and Platform Well Locations



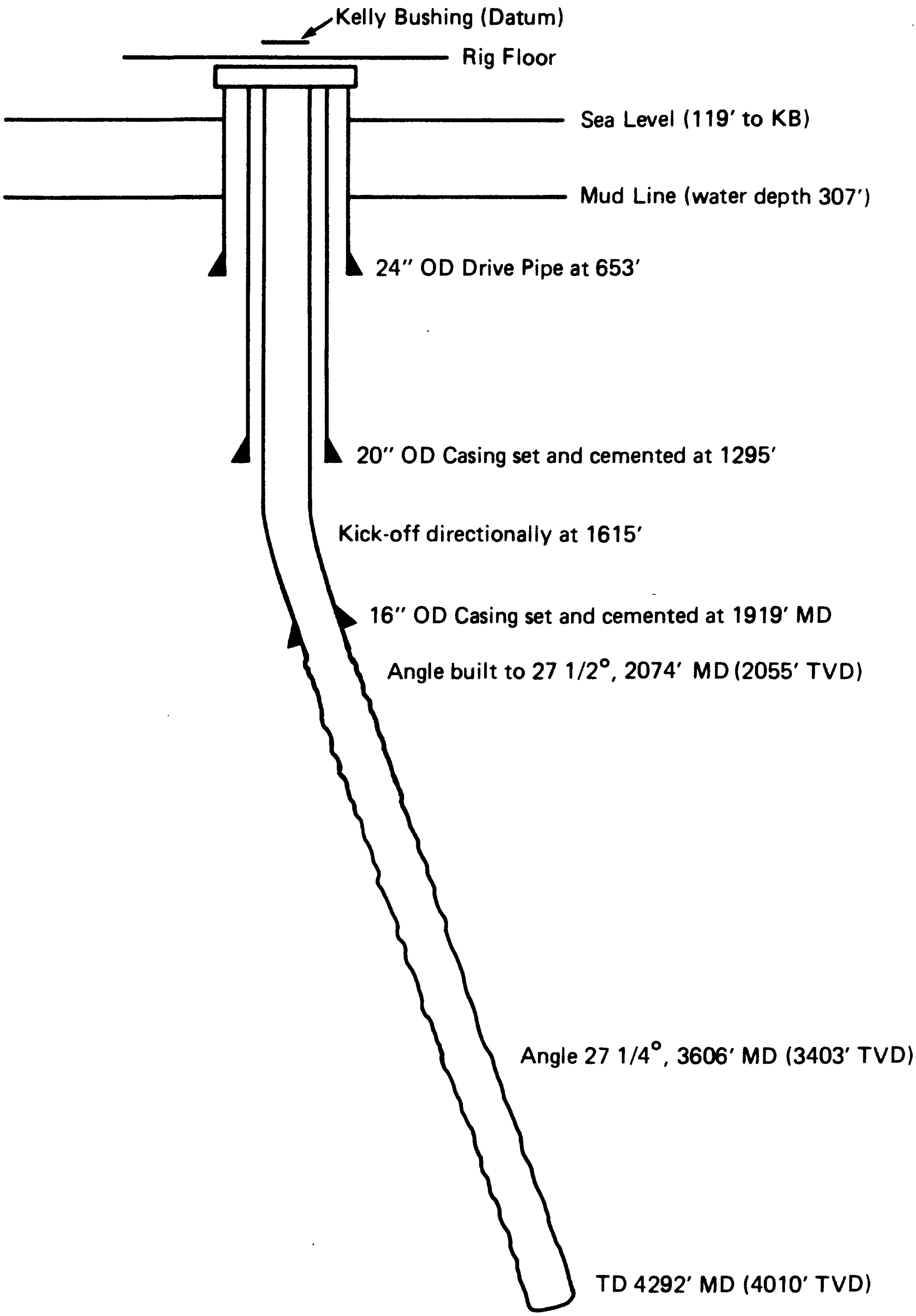
Diverter Manifold and Annular Preventer



* Pneumatic 8-inch diverter valves, used to divert either to the separator or to the horizontal line overboard.

Attachment No. 5

WELL A-10
LEASE OCS-G 2324
EUGENE ISLAND BLOCK 361



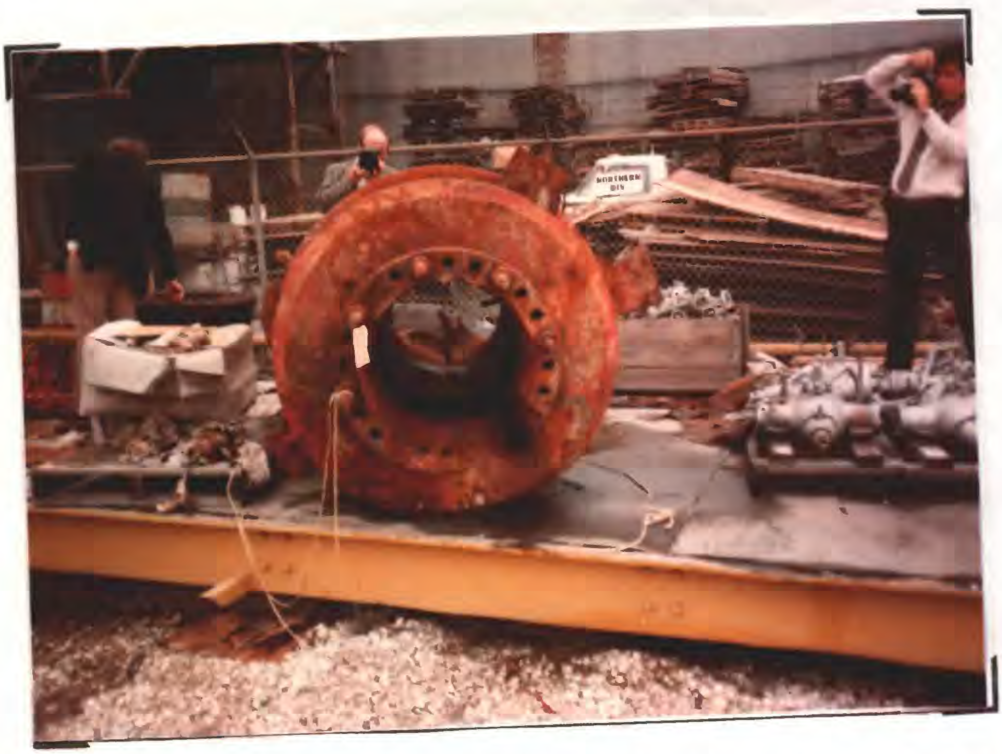
Photographs of the Well A-10 Blowout

Well blowing out before ignition, October 21, 1982

Well blowing out and afire, October 22, 1982

Attachment No. 7

Fire extinguished, well blowing salt water and gas, October 25, 1982



Flange cutout below the annular preventer by abrasive blowing action

Attachment No. 8

Diverter valve with broken connection downstream

Another view of the same equipment, including the actuator

Attachment No. 9

Diverter valve (with actuator) as connected to
diverter line to the outside

Attachment No. 10

Chevron's Posting on the Rig

DIVERTER
WELL CONTROL PROCEDURE

AT FIRST INDICATION OF A KICK THE DRILLER WILL:

1. SOUND ALARM.
2. WITH PUMPS RUNNING, PULL KELLY CLEAR OF ANNULAR PREVENTER AND SPOT TOOL JOINT CLEAR OF SEALING ELEMENT.
3. OPEN DIVERTER/CLOSE ANNULAR PREVENTER AND DIRECT FLOW DOWNWIND WITH REMOTE CONTROLLED VALVES.
4. SWITCH PUMP SUCTION TO SEAWATER WHILE KILL MUD IS BEING PREPARED.

GLOSSARY

abnormal pressure (n): Reservoir pressure above or below a 0.465 psi/ft pressure gradient or a 9.0 lb/gal equivalent. More commonly used in conjunction with higher gradients. Becomes significant when above about 0.5 psi/ft.

annular blowout preventer (n): A large valve which forms a seal in the annular space between the pipe and wellbore or, if no pipe is present, on the wellbore itself (not a ram-type preventer).

annulus (n): The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

bit (n): The cutting or boring element used in drilling oil and gas wells.

blowout (n): An uncontrolled flow of gas or oil, or other well fluids into the atmosphere.

borehole (n): The wellbore; the hole made by drilling or boring.

bridge over (v): The self sealing of a blowout in the borehole.

casing (n): Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the hole from caving during drilling and to provide a means of extracting petroleum if the well is productive.

cement channeling (n): During a cementing operation when the cement slurry fails to rise uniformly throughout the annulus, leaving spaces void of cement.

circulation (n): The movement of drilling fluid (mud) downward through the drill pipe and the upward return through the annulus. One circulation is one complete cycle.

conductor pipe (conductor) (n): A short string of large diameter casing, usually cemented, used concentrically in the drive pipe to provide a means of conveying the upflowing drilling fluid from the wellbore to the mud pit.

diverter (n): A system using large-diameter valves and pipes at relatively shallow depths to protect offshore rigs during blowouts by directing the flow away from the rig.

dogleg (n): A short change of direction in the wellbore.

drill pipe (n): The heavy seamless tubing used to rotate the bit and circulate the drilling fluid.

drill-pipe float (n): A valve installed in the drill steam that allows mud to be pumped down the drill stem but prevents flow back up the drill stem.

drill stem (n): The entire length of tubular pipes that makeup the drilling assembly from the surface to the bottom of the hole.

gas-cut mud (n): A drilling mud having entrained formation gas that gives the mud a characteristically fluffy texture.

gas kick (n): An entry of gas from a formation into the wellbore which occurs when the pressure exerted by the column of drilling fluid is not great enough to overcome the formation pressure and results in a mud-pit gain.

gas unit (n): A unit of measurement of gas concentration in the drilling mud as determined by service company analysts (not a standard measurement).

heaving or gumbo shale (n): A relatively sticky sedimentary rock, normal to the Gulf of Mexico, composed of swelling clays primarily and therefore more prone to sloughing than other more common shales.

kelly (n): The heavy steel member, four- or six-sided, connected to the topmost joint of drill pipe to turn the drill stem. It has a bored opening as a pipe that permits drilling fluid to be circulated.

kelly bushing (n): A device fitted into the rotary table through which the kelly passes and by means of which the torque of the rotary table is transmitted to the kelly and to the drill stem.

kick off (a well) (v): To deviate a wellbore from the vertical.

log (a well) (v): To run any of the various electric logging tools to ascertain downhole information about a well.

lost circulation (lost return) (n): The loss of quantities of drilling mud to a formation, evidenced by the complete or partial failure of the mud to return to the surface as it is being circulated in the hole.

mud (n): The liquid circulated through the wellbore during rotary drilling operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formations.

packing (of a borehole) (v): The accumulation of cuttings and hole sloughings in the annulus to such an extent that circulation is difficult and ineffecive and drill pipe movement causes swabbing or fracturing, according to direction.

pump out (a stand of pipe) (v): Under packed-hole conditions, to circulate a few minutes or longer prior to pulling each stand of drill pipe from the wellbore.

rotary table (n): The principal component of the mechanism used to turn the drill stem and support the drilling assembly. It has a beveled-gear arrangement to create the rotational motion and an opening into which bushings are fitted to drive and support the drilling assembly.

shoe (casing shoe) (n): A short, heavy, hollow, cylindrical steel section with a rounded bottom that is placed on the end of the casing string to serve as a reinforcing shoe and guide as the casing is being lowered. Testing after drilling out refers to pressure testing the formation just below the casing shoe to assure integrity.

spud in (spud a well) (v): To begin drilling; to start the hole.

squeeze (n): A secondary cementing operation in which cement is pumped behind the casing under high pressure to recement areas not cemented initially or areas where the cement has been damaged.

stage in (v): Under packed-hole conditions, to circulate a few minutes or longer prior to lowering each stand of drill pipe into the borehole.

stands (n, pl): The connected joints of pipe usually 90 feet long (3 lengths of 30-foot pipe screwed together).

swabbing effect (n): The phenomenon which occurs when drilling fluids on the outside of the drill stem fail to bypass the drill bit as it is pulled from the hole. Mud being swabbed out of a hole can lead to a kick if the mud is not replaced during a trip.

temporary abandonment (n): Abandonment of a well without placing a surface cement plug and cutting off and removing the upper portion of the casings.

trip (make a trip) (v): To hoist the drill stem out of the wellbore and then to return the drill stem to the wellbore.

underream (v): To enlarge the wellbore below the casing.

union (n): A coupling device that allows pipe to be connected without being rotated.

wellbore (n): A borehole; the hole drilled by the bit. A wellbore may have casing in it or be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.