

**Investigation of Loss of Control
Grand Isle Block 90, Well C-7ST
OCS-G 4003
November 14, 2002**

**Gulf of Mexico
Off the Louisiana Coast**



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

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Jack Williams – Chair
Lynard Carter
Randy Josey

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Investigation and Report

Authority

In November 2002, the Diamond Offshore Drilling, Inc. (hereinafter referred to as “Contractor” or “DODI”) jack-up rig *Ocean King* (hereinafter referred to as the “Rig”) was engaged in drilling operations for BP Exploration & Production Inc. (hereinafter referred to as “Operator”) on Grand Isle (GI) Block 90 Well C-7 sidetrack (ST). The Rig was in place next to the GI 93 “C” platform (hereinafter referred to as the “Platform”). Drilling operations were being conducted with the Rig cantilevered over the Platform using the re-claimed slot of the C-7 well, which had been plugged and abandoned (P&A’d).

Surface casing had been set and cemented to surface. After the cement had been in place approximately three hours, flow was noted coming from the surface/conductor casing annulus. The diverter was shut and pressure built up to 400 pounds per square inch (psi). Shortly thereafter, intermittent leaking of gas past the diverter flowline seals was noted. In the attempt to open the diverter ventline valves from a remote location to relieve pressure, it was found the valves could not be actuated. The Rig and Platform were subsequently temporarily abandoned because of the surface leak and subsurface pressure on the conductor casing shoe. The shallow-gas-pressure was fully contained within 8 days, at which point normal drilling operations resumed.

The event occurred 14 November 2002 at approximately 0230 hrs on the surface location in Operator’s Lease OCS-G 2628, Grand Isle Block 93, in the Gulf of Mexico, offshore the State of Louisiana. Pursuant to Section 208, Subsection 22 (d), (e), and (f), of the Outer Continental Shelf (OCS) Lands Act, as amended in 1978, and Department of the Interior Regulations 30 CFR 250, Minerals Management Service (MMS) is required to investigate and prepare a public report of this accident. By memorandum dated 26 November 2002, the following personnel were named to the investigative panel:

Jack Williams, Chairman – Office of Safety Management, GOM OCS Region
Lynard Carter – New Orleans District, Field Operations, GOM OCS Region
Randy Josey – New Orleans District, Field Operations, GOM OCS Region

Procedures

On the morning of 14 November 2002, personnel from the MMS visited the site of the incident to assess the situation. On 17 November 2002, representatives of the Operator met with New Orleans District personnel to review the incident and discuss ways to deal with the problem in future operations in the area. On 16 December 2002, members of the panel reviewed the incident by telephone with personnel of the Operator. On 11 February 2003, members of the Panel discussed the incident by phone with drilling engineering, geosciences, and supervisory personnel from the Operator to further clarify previously acquired information concerning the development of the shallow-gas hazard study. On 18 June the panel team interviewed Operator and Contractor management and engineering personnel. On 26 August, interviews were conducted with the principals present on the rig, and additional data were forwarded by the Operator. In addition to the interviews, other information was gathered at various times from a variety of sources. This information included the following reports and statements:

- Daily Drilling Reports, 13 October 2002 – 18 December 2002;
- Operator's Drilling Plan, Well No. C-7 ST;
- Operator's GI-90 Incident Investigation Report, 18 November 2002;
- Operator 3-Dimensional shallow-gas seismic analysis;
- Electric Log, Induction/Gamma Ray, Mobil Oil Corp. GI 93 Well No. C-2, 19 April 1975;
- Operator's measurement while drilling (MWD) log from Well No. C-7 ST;
- Operator's noise and heat transfer through-casing log on C-7 ST;
- Pictures of equipment, layout, and orientation of Rig and Platform;
- Diagrams of diverter system and control mechanism, description, operating service procedure;
- Contractor's Diverter Operation procedure;
- Interviews with Operator drilling management and engineering, geo-science, and operational personnel, Contractor drilling management, operational supervisors, and operational personnel;
- MMS records for all wells previously drilled from Platform including logs, plans, etc.;
- MMS Panel Report No. MMS 2003-23;
- MMS Safety Alert Notice No. 165.

Introduction

Background

The surface location for Well C-7 ST, Lease OCS-G 2823, covers approximately 5,000 acres and is located in Grand Isle (GI) Block 93, Gulf of Mexico, offshore, Louisiana (*for lease location, see Attachment 1*). Lease OCS-G 4003, the permitted bottom-hole location of Well C-7 ST, covers approximately 5,000 acres and is located in Grand Isle Block 90 adjacent to Grand Isle Block 93. These leases were issued to Mobil Oil Exploration and Producing Southeast, Inc. who became the operator effective 28 March 1974. Subsequently, Vastar Offshore, Inc. purchased the right and title in 1998 and assumed the role of Operator on 20 January 1999. Vastar was merged with BP Exploration and Production Inc. who became the Operator on 25 April 2002. The lease is owned by the Operator 100 percent.

The C-7 ST well was permitted to be drilled from a surface location in Lease OCS-G 2623 to a bottom-hole location (BHL) within Lease OCS-G 4003. This loss of control incident occurred while the well was still being drilled within Lease OCS-G 2823. However, after the loss of control was contained, drilling operations continued and the well was bottomed within Lease OCS-G 4003 as permitted. Because the well was completed as permitted and despite the BHL of the well at the time of the incident, the well is referred to by its permitted designation.

Brief Description, Loss of Well Control

In November 2002, the Rig was conducting directional drilling operations on GI-90 Well C-7 ST from the well's surface location on the "C" Platform of GI 93. Sixteen-inch conductor casing had been set at approximately 1,200 ft and cemented to surface. The well had been kicked off at approximately 1,200 ft and the angle had been built to approximately 60 degrees. The well had reached approximately 5,150 ft measured depth (MD). At 2300 hrs, 13 November 2002, surface casing was run to approximately 5,140 ft and cemented to surface with returns (*for well schematic at time of incident, see Attachment 2*).

At approximately 0230 hrs, 14 November 2002, the surface/conductor casing annulus started to flow gas and some fluid. The diverter sealing packer element (diverter packer) and diverter ventline valves were shut by placing the diverter system into "test." This action allowed holding

back pressure to attempt to let the cement cure. Pressure on the annulus then built to 580 psi. Intermittent leaking of gas past the diverter flowline seals was observed and heard to be increasing as the pressure mounted. Because of uncertainty of the cause of the leak, confusion about the integrity of the diverter flowline seals, and the fact that the event occurred at night, the Rig floor was evacuated. Attempts to open the diverter ventline valves to relieve the rising pressure, or to contain the diverter flowline seal leak by increasing the closing pressure of the seals, failed when the remote controls could not override the “test” mode. At 0515 hrs, with gas detected on the Rig and pressure rising on the annulus and presumably the conductor casing shoe, evacuation of all personnel on the Rig and Platform was completed.

By 16 November, personnel had re-boarded the Rig, contained the leaking seal elements and initiated kill operations. Isolation of the source of the annular flow of gas was subsequently achieved and the normal drilling operations were resumed by 22 November 2002.

Findings

Preliminary activities – Preparation of the well plan

The GI 93 “C” platform sits in 221 ft of water. The four-legged, eight-slot Platform was set in 1975 and six wells were drilled by the operator of the time, Mobil, from the Platform in 1975 and 1976. The lease was acquired by Vastar in 1998 and two additional wells were drilled in 1998-2000. Vastar merged into BP Exploration and Production Inc. and BP became the Operator in 2002.

In 2002, the Operator planned additional drilling from the “C” Platform. As all slots had been used, the Operator planned to P&A certain wells, reclaim the slots, and sidetrack to new bottom-hole locations. On 8 August 2002, during drilling operations on the first well in the program, the C-4 ST, a loss of control during drilling caused by an influx of shallow-gas from the “2,660-ft Sand” resulted in a diverter incident, fire, and evacuation of the Rig. The Rig sustained approximately \$2,000,000 in direct damages (see MMS Panel Report No. MMS 2002-023).

The second well planned for the drilling program was the C-7 ST. Because of the previous diverter incident and fire, a number of special efforts were made by the Operator in the planning of the C-7 ST well to prepare for the presence of shallow-gas. The Operator’s policy regarding shallow-gas hazards was revised. According to the Operator, the C-2 and C-7 wells were logged with noise and thermal logs to check for shallow flow. Two unused drive pipes on the Platform were tapped and checked for presence of gas. The diverter ventline piping was re-designed to include proper downwind alternatives and the diverter supports were greatly strengthened to prevent flexing under pressure.

Efforts were also made to identify the extent of the shallow-gas deposit that was the source of gas flow in the previous incident. A new shallow-gas hazard seismic survey was conducted and the results incorporated into the well plan. A through-tubing log was run in the C-7 well to attempt to determine the presence of the “2,660-ft sand” in the vicinity of the planned C-7 ST wellbore track. Additionally, an MWD log was specified to be used during the drilling of the surface hole of the C-7 ST.

The new shallow-gas hazard survey data failed to enable the Operator's geoscientists to define the extent of the 2,660 ft sand. However, based on the previous experience, the well plan specifically noted a "...high risk of shallow-gas flow in the surface hole, especially from the '2,630 ft sand' ['2,660-ft sand'] or others due to insufficient hydrostatic and/or swabbing." Methods of containing the shallow-gas hazard were incorporated throughout the well plan through setting of the surface casing. Changes from Operator procedure incorporated into the C-7 ST plan included tripping procedures, hole cleaning and circulation, mud weight, pipe running techniques and cementing, and cement composition, gas monitoring, simultaneous operation issues, and diverter drills. The Application for Permit to Drill (APD) and well plan contained some specific guidelines for the well supervisors to follow in case of a shallow-gas kick during drilling operations.

Risks of shallow-gas flow during cementing, specifically annular flow after cementing the surface casing, were also noted in the plan, and some risk mitigation actions were discussed. These included the mud properties to seal the sands, the type of cement, and other requirements. However, no procedures to deal with an annular flow after cementing were apparently included in the APD or well plan, other than the generalized "Diverter Procedure" in the APD. That "Diverter Procedure" stated the following: "...From the mudline to [about 4520 ft. true vertical depth (TVD)], a diverter will be utilized for well control. In the case of a shallow-gas flow, *no attempt will be made to shut in the well* with only structural (drive pipe and/or conductor) casing strings set..."

As an incentive to approach carefully the drilling and cementing of the surface casing in the C-7 ST, the Operator removed time incentives from the drilling contract and specified only safety as the determinant for incentives in this portion of the hole.

Drilling Activities — Events Through Loss of Control

(From drilling morning reports and interviews)

19 Oct. – 28 Oct. – The Rig moved on location to begin the drilling of the C-7 ST well. The plan called for plugging and abandoning the C-7, installing new 24-inch x 20-inch drive pipe, and setting 16-inch conductor casing at about 1,200 ft. The well was to be kicked off at about 1,200 ft

and 10¾-inch surface casing to be set at about 5,150 ft. Well C-7 was plugged and abandoned, casing cut and pulled.

28 Oct. – 6 Nov. – Drilled, milled, and drove new drive pipe to 690 ft. Spudded Well C-7 ST, drilled 16-inch conductor pipe for Well C-7 ST to about 1,200 ft MD, cemented to surface with 585 sacks of class H 11.4 pounds per gallon (ppg) lead and 593 sacks of class H 16.4 ppg tail with returns observed at the surface. No leak-off test was performed.

7-11 Nov. – Normal directional drilling operations, drilled to approximately 5,150 ft, pumping sweep every stand, mud weight (MW) 9.9 ppg.

12 Nov. – Pull out of hole (POOH), retrieve the log data from MWD, made wiper trip and circulated sweep that produced a measured 350 units of gas at the surface. After checking for flow and weighting up to 10.2 ppg, the well was re-circulated and crew prepared to set surface casing.

13 Nov. – POOH, rig up casing crew, run 10¾-inch surface casing to approximately 5,140 ft. Cement with lead 1,485 sacks class H, 11.4-ppg lead and 563 sacks class H 16.4-ppg tail; total volume included a 100-percent excess. Returns were received at the surface, drop and bump plug with 1,400 psi, cement in place at 2245 hrs, floats held. Run 1 inch into 10¾ x 16-inch annulus, wash cement at 5 barrels per minute (bpm), 15 min. wash, 5 min. monitor, until returns are clean.

14 Nov. 0230 hrs – While the casing valve was being monitored, the well was observed to start to flow. The casing valve was shut and the riser was filled with seawater.

0245 hrs – Shut well in by placing diverter in “test” mode. Pressure increased to 400 psi. Diverter flowline seals started to leak. By using the lines connecting the diverter housing to the choke manifold (*see Attachment 3*), pressure was twice bled back to 350 psi. Pressure built back to 400 psi both times with increasing flow and fluid returns. Pressure increased to 580 psi, flowline seals leak increased. When gas was detected on the Rig floor, the crew abandoned the floor, leaving the system in the “test” mode. Attempts were made to open diverter ventline valves from tool pusher’s remote station to relieve pressure. Remote would not override “test” mode and open the diverter. It was also found that the diverter flowline seal pressure could not be

raised from the remote site. At the remote site, the existence of a previously installed transponder-linked monitoring system provided the ability to monitor pressure.

0315 hrs - 50 nonessential personal evacuated to M/V *Sorolta Marie* and transferred to GI 94B platform. Seals continue to leak.

0515 hrs – Last pressure monitored was 340 psi., remaining 15 personnel evacuated by boat to GI 94 “B.”

Drilling Activities — Events to Regain Control

1200 hrs. – The Operator and Contractor personnel conducted a visual inspection from helicopter. No pollution or gas was observed leaking from the diverter. At 1400 hrs, MMS, Operator, and Contractor personnel made a boat reconnaissance and observed no pollution, no visual leaks from diverter housing.

1500 hrs – Personnel from the Operator, Contractor, and Wild Well Control boarded Rig by helicopter, conducted walk-around inspection, checked gas levels and casing pressure. They noted 10¾ x 16-inch annulus pressure of 260 psi, no 10¾-inch pressure. They observed a slight gas leak through the top diverter flowline seal (12% lower explosive limit (LEL) reading on the gas detector at the rotary table, 4% LEL reading 10 ft from rotary table).

15 Nov. 0700 hrs – A four-man team arrived at the Rig by helicopter and checked for gas flow and pressure. They found a shut-in annulus pressure of 260 psi and observed a continuing slight intermittent leak around the upper flowline seal. A start-up crew was mobilized under the lead of Wild Well Control. The crew boarded the Rig and powered up essential equipment on the Rig floor. Using the controls on the driller’s console on the Rig floor, the closing pressure on the diverter flowline seals was increased from 260 psi to 350 psi and the leak was observed to be contained. The crew continued to increase pressure on the seals to 550 psi, and seal pressure ultimately was raised to over 900 psi. Shut-in casing annulus pressure then increased to 300 psi and stabilized. The remaining necessary personnel were mobilized from GI 94 “B” and boarded the Rig at 1200 hrs.

1200 – 1600 hrs – Seven additional personnel boarded the Rig and the crew built a 125-barrel volume of 17.0-ppg kill weight mud. The crew then rigged up chocks and lines from the choke manifold for lubrication purposes. Keeping the diverter fully closed in, they tested the lines and bled off the pressure from 300 psi to 150 psi. The pressure built back to 300 psi in 40 min. Crew began work to kill the well.

15 Nov. – 23 Nov. – Work continued to kill well, including running cement bond log (CBL) and other logs to evaluate possible flow. According to the Operator, the analysis of the CBL was inconclusive for identification of any micro annulus, and no subsurface flow was identified from the noise and thermal logs. Attempts to block squeeze at 2,100 ft were unsuccessful because pump-in or circulation could not be established. The crew then perforated the casing at about 1,160 ft, just above the conductor casing shoe, and established annular circulation to the surface. Heavy mud was circulated, followed by cement, which was circulated and then squeezed into annulus, successfully killing all pressure and flow. Normal drilling activities were resumed.

Findings – Details and Context of Specific Events

Shut-in of well using diverter system

The diverter used on the Rig was a KFDJ diverter that features a telescopic riser. This type of diverter has a standard main diverter packer element that is pressured up by pneumatic or hydraulic means to close the casing annuli in the event of unexpected pressure or shallow fluid influx. But, because of the telescopic arrangement of the riser, it also features hydraulically controlled diverter flowline seal elements that bracket the mandrell housing the diverter ventline(s) exit (*see Attachment 4*). These diverter seal elements are energized by applied hydraulic pressure “locked” by a check valve. The seal pressure can be varied from 0 psi to 2,000 psi (depending on model) from either the driller’s console on the rig floor or from a remote station. The seal pressure is controlled hydraulically, and the seals are not self-energizing. The diverter flowline seal element pressure can also be manually controlled from a pump located next to the driller’s console on the Rig floor. A “test” mode allows the entire system, the diverter packer element, all valves, etc. to be shut in by interrupting the pneumatic supply to the actuators.

When the conductor/surface casing annulus began to flow, the diverter system was shut in using the “test” mode in order to hold back-pressure. From testimony, this initial decision to hold pressure rather than divert the well was made by Operator and Contractor supervisors on the Rig in consultation with shore-based support and management personnel. The system was placed into “test” because the alternative, the activation of the diverter, would have sent the well flow and pressure immediately into the open ventlines for at least 30 seconds, possibly resulting in a full-scale loss of control similar to the C-4 ST incident. The supervisory personnel of Operator and Contractor felt that the annulus pressure could be contained and held by the diverter until the cement healed enough to seal the micro annulus. The well plan contained no formal procedures or recommendations for actions in this type of an event.

The Operator’s APD defined the normal mechanical sequence of diverter operations as follows: “... (1) When the well is determined to be flowing requiring use of the diverter, close the diverter element. This will also automatically open all the valves for the diverter ventline (s) [in this case three lines leading port, starboard and aft]. Thereafter, [in this case, after approximately 30 seconds], the system will allow closing all but one of the ventline valves so as to divert the flow to the downwind line.” However, the operating instructions include a description of a

method of fully containing pressure with the diverter packer element shut without using the test mode. That procedure notes, “After a time delay of approximately 30 seconds, the diverter shut-in valve can be closed and the diverter choke valve opened. This will allow circulation of the well using normal well control techniques.”

At the time of the incident, MMS regulation 250.409 (c) required the diverter system to be “...equipped with remote-controlled valves in the flow and vent lines that can be operated from at least one remote-control station in addition to the one on the drilling floor...” Regulation 250.409 (f) requires “The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nipped up on conductor casing ...No more than 7 days shall elapse between subsequent similar pressure tests...the diverter sealing [packer] element, diverter valves and diverter-control systems, including the remote control system, shall be actuation-tested and the vent lines flow tested when first installed. Subsequent actuation tests shall be conducted not less than once every 24-hour period thereafter alternating between control stations.” On the Rig, the functional tests of the diverter system consisted of opening and closing the components from both the driller’s console and from the remote location. The pressure test was hydrostatically conducted against a completely closed diverter system placed into the “test” mode after conductor casing was set.

Of note is MMS Safety Alert Notice No. 165, issued 3 April 1995 (*see Attachment 5*). In that Alert, over 20 loss of control incidents (from 1973 to 1995) caused by shallow-gas influx during or immediately after surface casing cementing are referenced, and four are discussed in some detail. Of the four cases referenced in some detail, fracturing the formation at the casing shoe, followed by surface breaching, was the most serious consequence with major damage and/or loss of a rig narrowly avoided in that case.

Safety Alert No. 165 addressed some of the issues involved in dealing with flow after cementing and noted that “...it may be desirable to hold slight back pressure on the annulus after cement is in place, and to consider shut in of the well rather than diverting the well. In these cases, leakoff testing of the conductor casing shoe is recommended to better predict the surface pressures that could later be withstood without fracturing....Any applied back pressure should not be enough to cause the formation at the conductor shoe to break down....”

To pressure test the KFDJ diverter, it is necessary to have the diverter packer element sealed by a test plug, or to have the packer and all valves closed, a condition that is only possible after the elapse of 30 seconds unless the “test” mode is activated. To place the system in the “test” mode, the driller’s console included a lever that interrupted the pneumatic air supply. This disabled the system interlocks, which normally automatically allow valves to shift open when the diverter packer element is closed. However, the operating and service procedures note that this “test” mode interruption of the pneumatics eliminates the ability to control the diverter from the remote console until the “test” control is de-activated. In the “test” mode, the control of the diverter is still possible from the rig floor panel, but the absence of interlocks requires that each function be conducted independently.

Testimony indicated that the Operator and Contractor Rig supervisors were unaware that use of the “test” mode disabled the ability to control the diverter from the remote location. They were also not sure of the pressure limits of the flowline seal elements (see below). Testimony also indicated that it was unclear to Operator and Contractor supervisory personnel what would happen if the diverter were removed from the “test” position. Some personnel thought that if the system was thus operated, the diverter packer element might automatically open first while the main valve on the diverter ventline(s) closed. Testimony indicated that it was thought the system on the Rig may have been so configured. In that case, any attempt to remove the diverter control from the “test” mode could have resulted in opening the diverter packer element and releasing the pressure beneath the Rig floor rather than out the ventlines.

According to testimony, no formal procedure for conducting operations under pressure with the diverter system shut-in was available to the personnel on the Rig. There was no testimony or information indicating that prior planning anticipated the possible need to use the diverter as a pressure-holding device. No leak-off test had been performed to determine the fracture pressure of the conductor casing shoe, and the Rig personnel apparently had no written guidelines to follow when holding pressure on the cement.

Ability of diverter to sustain pressure

The KFDJ diverter flowline seal elements periodically began to leak when the pressure exceeded 400 psi. It is not fully clear what closing pressure was hydraulically applied to the seal elements

when the elements began to leak. However, 260 psi was the seal pressure found when the Rig was later re-boarded.

Testimony indicates that the Rig supervisory personnel initially thought 300 psi was the pressure capacity limit of the seals. This pressure was quickly exceeded by the annular pressure build-up. At that moment, there was a concern among operating personnel that attempting to pressure up the seals above 300 psi might risk the integrity of the seal elements themselves, possibly leading to full surface loss of control beneath the Rig floor. Testimony also indicates some uncertainty among the Rig supervisory personnel about the pressure limitations of the entire system, including the pressure rating of the diverter packer element. Some confusion as to whether the flowline seals contained a self-energizing feature (they do not) apparently continued after the event was contained.

From testimony, only after the floor was abandoned was it discovered that the diverter system could not be controlled from the remote station when in “test” mode. A brief consideration was apparently given to the possibility of using an expedient manual means, such as a lasso or hook, to disengage the “test” mode lever on the driller’s console. However, the inherent danger and the uncertainty about the method required to remove the system from test, keep the diverter packer element closed, and simultaneously open the diverter ventline valves led to rejection of that alternative.

According to testimony, the inability to open safely the diverter ventline valves to relieve the pressure, the presence of gas on the Rig, and the pressure the shut-in diverter allowed to be applied to the conductor shoe led to the decision to fully abandon the Rig and Platform.

After a period of time to analyze the engineering of the seal elements, the Operator and Contractor personnel concluded that the flowline seal leak could be contained by raising the seal pressures, and that access to the Rig floor was necessary to do that. Technical assessment of the causes of the leak focused on two possibilities: Either the internal pressure exceeded the pressure setting of the seals, and/or the rocking motion of the rig resulted in placing some mechanical pressure that periodically varied the flowline seal pressure. After the wind increased, dispersing the gas present on the Rig floor to the point that access could be safely regained, crew members led by Wild Well Control personnel boarded the Rig floor. They found the pressure on the annulus had dropped to approximately 260 psi. The team then powered up the Rig floor and used

the driller's console control to raise the hydraulic pressure of the flowline seals from 260 psi to 350 psi, successfully containing the surface leakage.

No firm explanation could be established to explain the drop in annulus pressure from a maximum of 580 psi just before the evacuation to the 260 psi observed when the Rig floor was regained. No evidence of surface breaching around the Rig or Platform was reported.

Conclusions

The incident consisted of a surface and subsurface loss of control of shallow natural gas during surface casing cementing operations. The loss of control precipitated a rig evacuation. No pollution, injuries, or damage resulted from the incident.

Cause of Loss of Control — Subsurface

The loss of control of the subject well was caused by an apparent micro-annulus created during the cementing of the surface casing. This micro-annulus allowed gas from the “2,660-ft sand” to migrate behind the surface casing, past the conductor casing shoe, and into the annulus (*see attachment 2*). Specific actions on the Rig allowed the pressure on the subsurface formations and the conductor casing shoe to rise to levels untested by drilling or leak-off. The subsurface pressure created the possibility of breaching to the surface.

Cause of Loss of Control — Surface

The potential for surface loss of control was caused by pressure at the wellhead channeled from the “2,660-ft sand” through a micro-annulus created during cementing of the surface casing.

The leakage of gas through the diverter flowline seals of the KFDJ diverter system onto the Rig floor created the actual surface loss of control. It is not known for certain why the diverter flowline seals failed to contain the pressure. However, after the leak in the seals was confirmed, the crew failed to contain the leak by raising the hydraulic seal pressure because of uncertainties about pressure limitations of the seals.

Cause of Rig Evacuation

The loss of control, both surface and subsurface, resulted in the evacuation of the Rig and Platform. There were three causes of the need to evacuate: (1) A cause and effect series of events and decisions, (2) Lack of knowledge of the system, and (3) Lack of pre-event planning and procedures.

(1) The cause and effect series of events and decisions leading to the evacuation were as follows:

- (a) The gas migration caused surface pressure and green cement/gas flow from the casing annulus, which led to *the decision to hold pressure on the annulus* to allow the green cement time to cure, rather than divert the flow;
- (b) To hold pressure on the annulus, a *decision to place the diverter into the “test” mode was made*, as it was the only way to shut in the system fully and immediately. As the pressure rose, the flowline seal elements developed the aforementioned intermittent leak, causing gas to be released on the Rig floor;
- (c) *The leak was not contained by raising the flowline seal pressure because of uncertainty about the pressure handling capability of the diverter system.* Thereafter, the continued leak of gas created conditions that required the evacuation of the Rig floor;
- (d) *The diverter control was left in the test mode* during the evacuation of the Rig floor, which made control of the diverter valves and system from the remote station impossible;
- (e) *The design of the diverter control was such that the diverter could not be controlled from the remote location with the system in “test.”* This eliminated the ability of the crew to operate the diverter from the remote location to contain the diverter flowline seal leak by raising the seal closing pressure. It also made it impossible to relieve the pressure on the subsurface formations and casing shoe by opening the diverter valves;
- (f) *The crew was unaware that the “test” mode disabled the remote station diverter control;*
- (g) *The backup manual control of seal pressure was not accessible* because it was on the rig floor next to the driller’s console;
- (h) *The shut-in diverter allowed pressure on the shoe and formation that was higher than that used during any test or drilling activities.* No conductor casing shoe leak-off test had been preformed.

At the conclusion of this series of events, the evacuation of the Rig ensued because of the potential for damage and danger should the gas breach the surface.

(2) Lack of knowledge of system:

The Rig evacuation was in part caused by the Contractor and Operator field personnel's unfamiliarity with the KFDJ diverter system. The crew did not have sufficient knowledge about flowline seal pressure capabilities, flowline seal pressure activation, diverter packer element pressure capabilities, and the details of operating the system under "test" conditions. It is unknown whether the lack of knowledge was related to lack of training, technical information transfer, or lack of technical information availability.

(3) Lack of pre-event planning and procedures:

No written procedure or plan was apparently prepared by the Operator or Contractor for contingency actions to contain annular flow after cementing. There were also apparently no guidelines prepared for the procedures to be followed when holding back-pressure by using the diverter. There were also no instructions as to the limits of the pressure to be held by the diverter before threats to the integrity of the shoe required the opening of the diverter valves. There was no shoe test to establish safe limits for holding back pressure with the diverter. There were also no drills and no readily available contingency plans that identified the options if the diverter system were used to contain pressure in the "test" mode.

Possible Contributing Cause of Loss of Control and Rig Evacuation

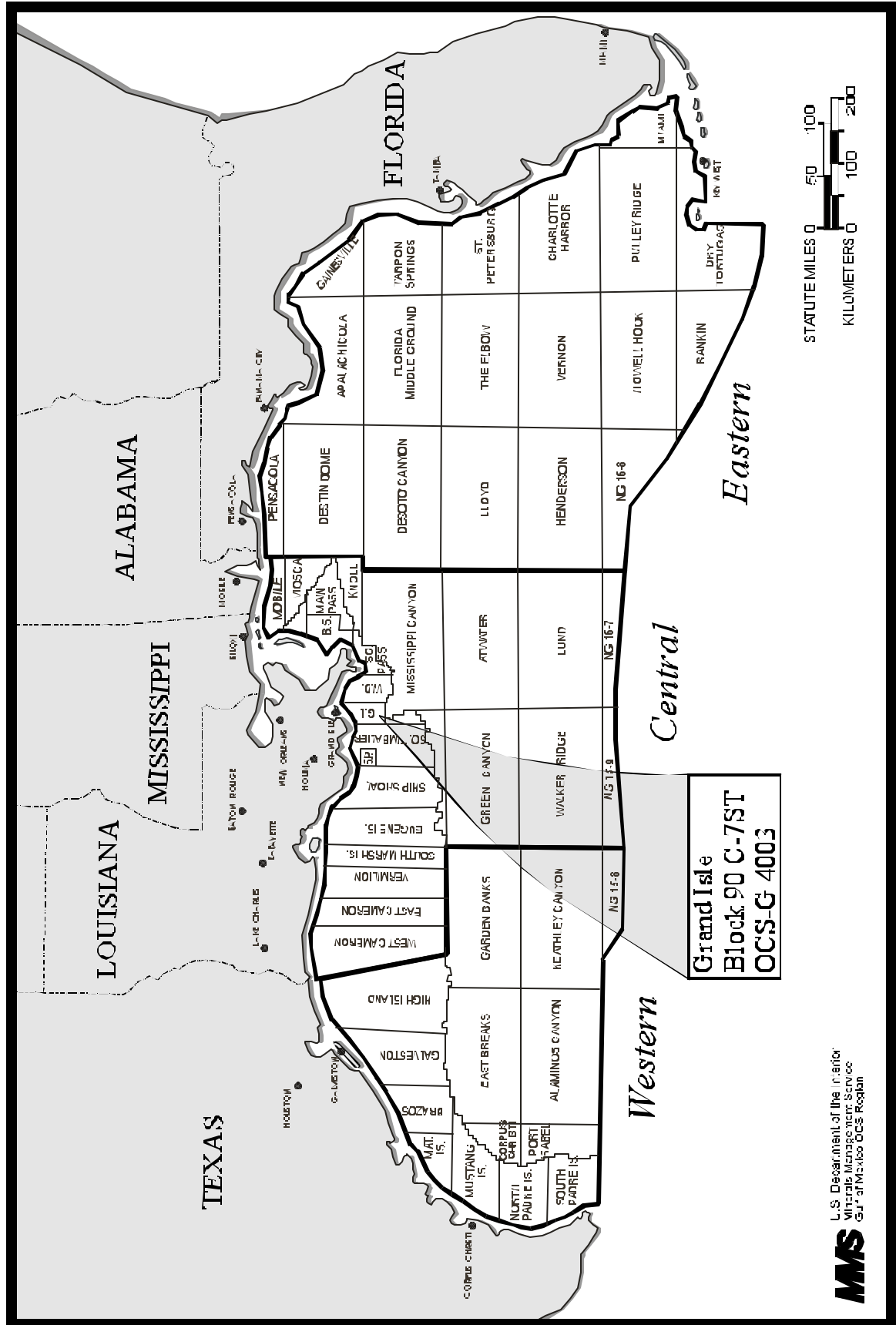
It is not known exactly what caused the flowline seal leak. However, it is possible that the flowline seal pressure was set at 260 psi, as that is the pressure found when the Rig floor was accessed during kill operations. Because the annular pressure is reported to have reached as high as 580 psi, the inability of seals set at 260 psi to contain that pressure is a possible cause of the leakage. It is also possible that the intermittent leak of the diverter flowline seals was related to compression and tension forces transferred to the seal elements by the rocking motion of the Rig. These forces, when added to the casing pressure, possibly created an intermittent leak by momentarily causing the shut-in pressure of the seals to be exceeded as the Rig swayed.

It is possible that any use of the “test” mode of the diverter system to hold pressure made it impossible to actually safely return to the standard operating mode under pressure. Some indications are that when similar diverters are removed from the “test” mode, the first action that occurs is the opening of the diverter packer element and the closing of the main ventline valve. If the system on the Rig was configured in the same manner, switching out of the “test” mode could have resulted in a sudden, major release through the diverter packer. Therefore, activation of the “test” mode may have effectively “locked” the system into that mode until the pressure was killed.

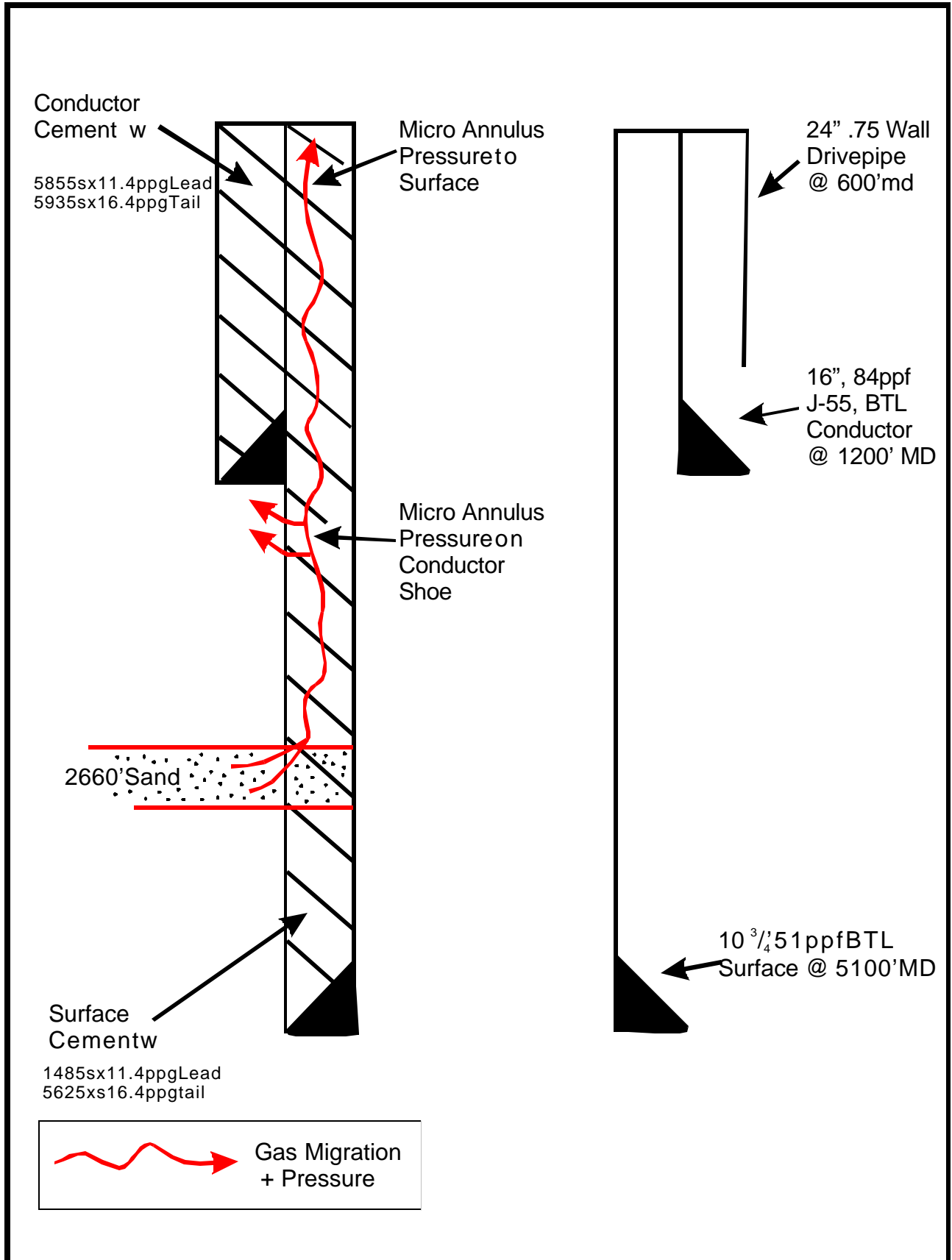
Recommendations

It is recommended that MMS consider initiating a study of regulations, recommendations, or procedures to be followed before allowing a shut-in using the diverter during cementing. Among the topics of consideration is that a number of parameters should be defined before holding pressure by closing the diverter. These include, but are not limited to, a known pressure limit to be determined by leak-off test, adequate monitoring of pressure; and diverter operating procedure.

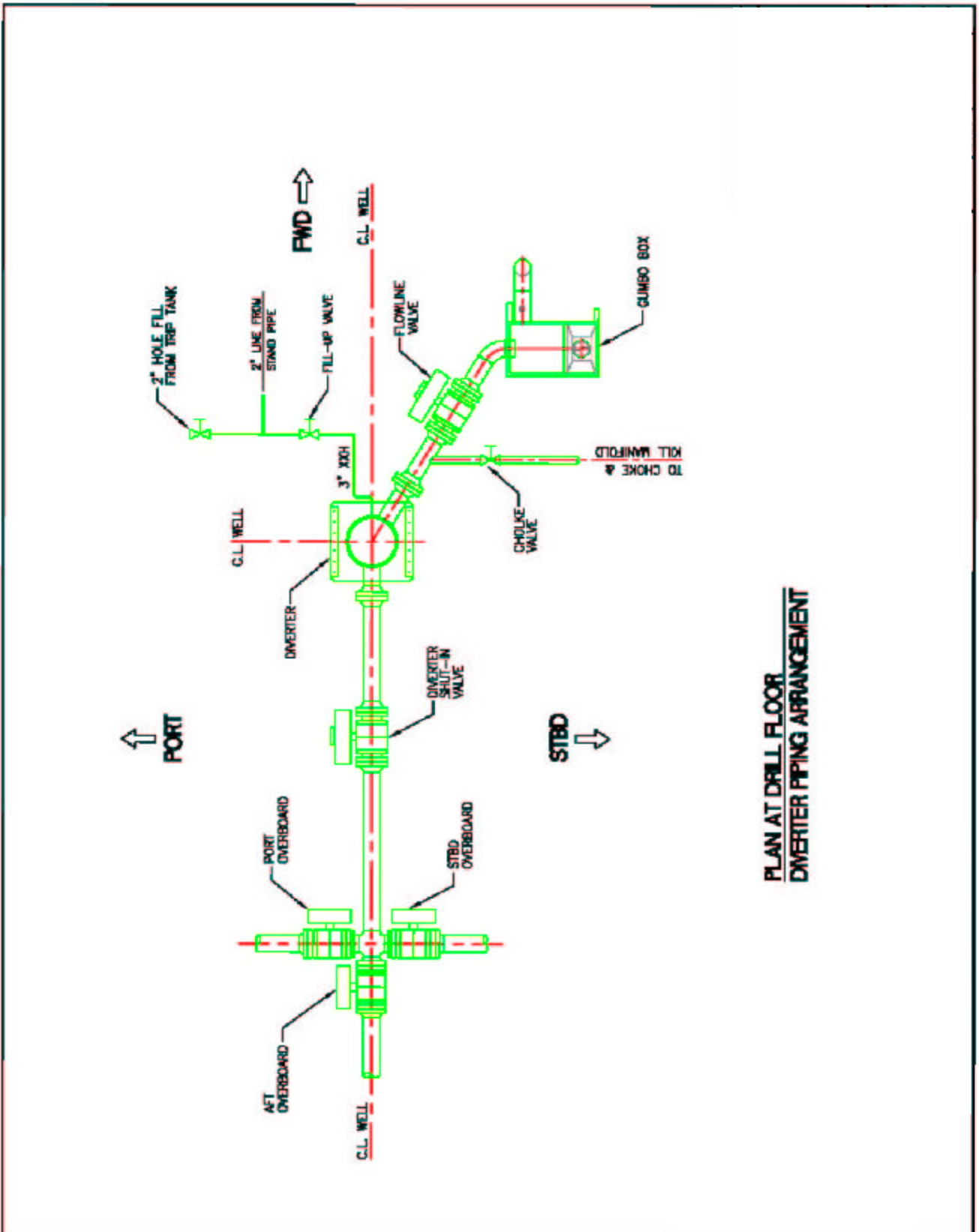
It is also recommended that MMS issue a Safety Alert regarding the subject incident.



Location of Lease OCS-G 4003, Grand Isle Block 90



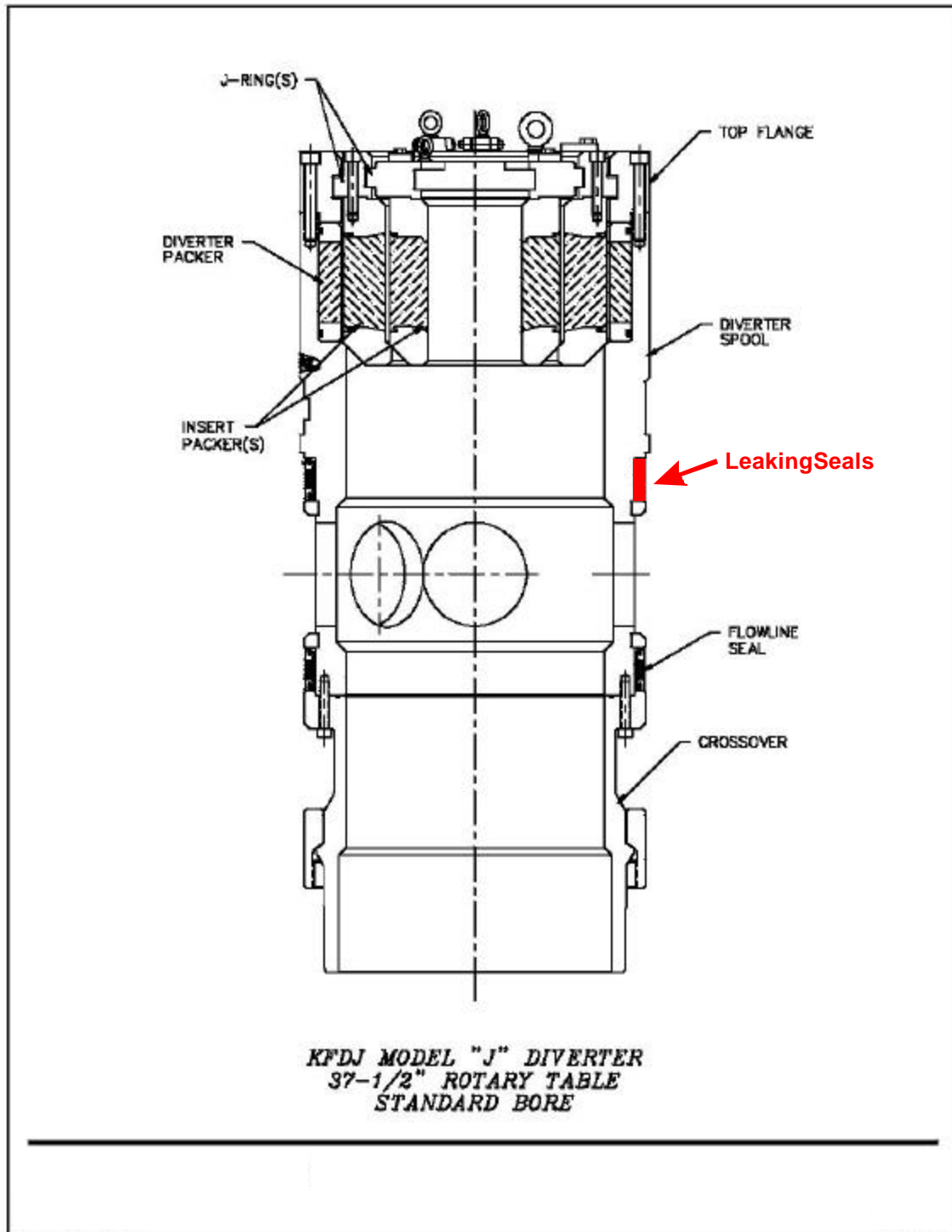
Grand Isle Block 90 C-7ST Well Schematic at time of LOC



**PLAN AT DRILL FLOOR
DIVERTER PIPING ARRANGEMENT**

Diverter Piping Arrangement

ABB VETCO GRAY
KFDJ MODEL J DIVERTER



Schematic of diverter and source of leak.



Notice No. 165

April 3, 1995

Shallow Gas Flows While Cementing Surface Casing

A well recently blew out while waiting on cement after surface casing was set. After the wiper plug was bumped, the casing was pressure-tested and sugar water was spotted on top of the mud line hanger. The well was static for four hours, and the operator commenced to nipple down the diverter system. Two hours later, the well started flowing gas and cement out the open diverter. The diverter was closed, and the loosened bolts that attach the diverter to the conductor casinghead were reinstalled. Efforts were unsuccessful to stem the flow by pumping saltwater through the conductor casing valve while allowing the well to unload out both 10-inch diverter lines. Approximately one-half hour after the well started unloading, flow began coming from the annulus between the drive pipe and the conductor, and the rig was evacuated.

Several unsuccessful attempts were made to control the flow. Six days after the flow began, the flow rate decreased and the rig was able to move off location. Four days later, the drive pipe, conductor, and surface casings fell to the seafloor and the flow ceased. The next day, a subsea inspection by a remote operated vehicle (ROV) revealed a 25-foot crater at the base of the drive pipe with no bubbles or flow observed. Five months later, another rig moved on location and successfully completed abandonment of the well. There were no injuries or fatalities as a result of this blowout.

A similar incident occurred in July 1994 while spotting water mixed with lignosulfonate (ligno water) after washing the annulus through wash ports on the mud line hanger. After the 20-inch surface casing was cemented, the annulus was washed by circulating through ports on the mud line hanger, and ligno water was spotted. After a gyro survey was run, a diverter line was opened to check for flow. Flow was noticed on the annulus and the diverter line was closed. The annulus pressure was alternately bled off and allowed to build up during the next day. During the next two days, unsuccessful attempts were made to place heavy mud into the annulus by injection and by circulating through the mud line

hanger. The well was finally killed by placing 3/4-inch tubing into the annulus and circulating heavy mud. Operations were resumed some three days after the flow began. There were no injuries or fatalities associated with this incident.

In another, less serious incident, a shallow gas flow also occurred after the surface casing was cemented. Nippling down of the diverter was begun seven hours after the plug was bumped and the float valves were checked. The diverter and diverter lines were rapidly reinstalled when flow first began. The well was shut in with a surface pressure of 50 psi, and was killed by lubricating mud into the annulus between the conductor and the surface casings. The annulus was then successfully grouted, and normal drilling operations were resumed 5 3/4 days after the flow first began. There were no injuries or fatalities as a result of this incident.

In still another incident, nipple down of the diverter system and installation of the casing slips were completed two hours after the plug on the surface casing was bumped. A slight gas flow was ignited by a welder making a rough cut on the surface casing one-half hour later. The gas was flowing from a casing valve that was open so that the annulus could be monitored. The flame was extinguished with no damage or injuries when the casing valve was closed. However, when the valve was later reopened, mud and gas flowed from the well. The valve was closed and the diverter was reinstalled on the wellhead. At this point, the seal on the casing slips failed, and 15-20 bbls of mud and gas were discharged through the diverter line. When fluid slowed to a very small stream, a line was connected to the casing valve, and 3 3/4 bbls of mud was pumped between the 13 3/8-inch and 20-inch casings. The well was monitored for 16 hours and 6.9 bbls of mud were recovered. Final flow rate was 2 1/2 gallons per hour, and at this point, the crew prepared to resume normal operations. The lead cement had thixotropic properties typical of slurries used for this application.

All four cases were caused by formation fluids migrating into the annulus as the cement went through a transition before compressive strength was developed. Sixteen similar well-control incidents have been reported since 1973.

The best way to avoid these problems is to select, on the basis of the shallow hazards survey, a surface location that is not directly above a seismically visible shallow gas accumulation. However, if well objectives require drilling from a location in a shallow gas area, or if it is likely that gas sands will be penetrated in the surface hole, appropriate consideration as to how to handle any shallow gas related problem that might arise should be developed when the well is planned. This consideration is particularly important where the hydrostatic head is to be reduced by activities such as washing mud or cement from the upper annulus with water to facilitate future abandonment.

Items to be considered in shallow gas areas may include the following:

1. Improving cement properties to minimize chances of shallow gas flow, including density, fluid loss, transition time, compressibility, etc.

2. Planning for optimum cement column length (within guidelines established in 30 CFR 250.54)
3. It may be desirable to hold slight back pressure on the annulus after cement is in place, and to consider shut-in of the well rather than diverting the well. In these cases, leakoff testing of the conductor casing shoe is recommended to better predict the surface pressures that could later be withstood without fracturing. Based on results of the leakoff test, the amount of back pressure that could safely be applied until cement has achieved compressive strength should be calculated. Any applied back pressure should not be enough to cause the formation at the conductor shoe to break down, and the annulus should be bled as required to avoid breakdown.

The considerations made regarding shallow gas should also seriously address whether or not the parameters associated with a particular well suggest diversion after cement is in place as a viable option. These parameters include leakoff test data and various depths at which gas sands may be drilled in the surface hole. The mindset that "diversion is the best option because a diverter system is in place" may need to be reexamined. In many cases, the planned shut in of a well may provide for a safer means of well control than diverting the well, especially after cement is in place.

Current regulations require waiting on cement for 12 hours before drilling out all casing strings other than the conductor casing, and that cement have a minimum of 500-psi compressive strength in the bottom 500 feet. This waiting time does not specifically apply to the nipping down of the diverters. In 3 of the above 4 cases, diverters had been partly nipped down in substantially less time than 12 hours after the plug was bumped. It was fortunate for the rig crews that the diverters were able to be reconnected before the flow became prohibitive. The proper amount of time to leave the diverter system in place is dependent upon the time required for the cement to develop adequate strength to prevent gas flow. (Flows began in an average time of 4.5 hours and a maximum time of 10.5 hours after the plug was bumped in 13 of the incidents for which information was available.)

A better determination of the time required for waiting on cement would be based on lab tests of the cement properties rather than time alone. The Minerals Management Service plans to investigate the issue of waiting on cement. The goal is to better understand well bore cement properties, particularly compressive strength, and how they can be used to establish an acceptable criterion for waiting on cement. This could lead to a regulatory change that better recognizes cement performance criteria and the importance of when well control equipment is nipped down in lieu of the rigid waiting on cement time prior to drilling out of casing in our current regulations.

A Regional Offshore Technology Assessment Committee workshop has been planned for May 23, 1995, at the Lod Cook Alumni Center at Louisiana State University, in Baton

Rouge, Louisiana. The forum will provide industry and MMS with the opportunity to discuss issues, concerns, and potential remedies regarding waiting on cement. This effort is a first step at better understanding cement properties and improving the ability to prevent shallow gas flows while waiting on cement.

The enclosed agenda for the workshop should be viewed as a guide to focus the discussions. Any recommendations for additional agenda items and participation by your company would be appreciated.

Enclosure