



Reverse Foam Cementing an Offshore Production Tieback

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Abstract

The first reverse-circulation foam cementing of a tieback string in an offshore environment was successfully performed in the Gulf of Mexico. This innovative approach to cementing a production tieback was performed for the following reasons:

- Reverse-cementing can place cement near the top of the annulus with no nitrified cement returns to surface.
- Reverse-cementing can enable the top of cement (TOC) to be lightly retarded for better compressive strength. The TOC slurry does not encounter high bottomhole temperatures (BHTs).
- The mechanical resiliency of foamed cement can maintain annular isolation and withstand the extreme stresses of high-temperature production.

This paper provides an overview of several innovative technologies and logistics solutions that contributed to the success of this cementing operation. The paper discusses the unique cementing equipment used and illustrates the piping layout applied. The job data and documentation of a reverse foamed-cement placement is also included. The tieback-cementing advancements presented have numerous potential applications in the Gulf of Mexico.

Introduction

Two deep, high-temperature wells were recently drilled and cased in the Mobile Bay area. One well was drilled in federal waters approximately 3.5 miles south of Dauphin Island; the second was drilled in the Fairway Field, located at the mouth of Mobile Bay within Alabama state waters approximately 2.5 miles south of Dauphin Island (Fig. 1).

The main geologic objective was the Jurassic Norphlet formation, a single eolian sand package that ranges in depth from 20,000 to 22,000 ft. Natural gas produced from the Norphlet formation in Mobile Bay may be sour with concentrations for H₂S ranging from 100 to 16,000 ppm. The casing design selected used a 6 ⁵/₈- × 7 ⁵/₈-in.

production liner across the productive Norphlet interval.

A 7 ⁵/₈-in. production tieback casing provided a pressure-containing system from the base of the production liner to the surface. A foamed-cement slurry was selected to provide isolation and casing support throughout the life of the well. The method for placing the foamed-cement slurry in the annulus was reverse-circulation.

Reverse-circulation was used for both tieback strings in these two wells. While reverse-cementing with foamed cement has been practiced for many years in onshore operations,¹⁻³ this was the first application in an offshore environment. This paper focuses on the planning and execution of the reverse-circulation, foamed-cement job conducted on the 7 ⁵/₈-in. production tieback installed in the Fairway Field well.

Well Data

Figure 2 shows the drilling plan for the well in Fairway Field. The well was drilled as a directional well with a horizontal displacement of 6,400 ft at the total depth (TD) of 21,555 ft true vertical depth (TVD). The well was drilled with a constant drift profile requiring a kickoff point at 9,500 ft measured depth (MD) and a tangent angle of 33°.

The thermal gradient for the Fairway Field wells is approximately 1.5°/100 ft, and the estimated BHT at TD was 410°F. The pore pressure in the Norphlet formation has depleted to approximately 7.0 lb/gal from an original pressure of 12.2 lb/gal. Water-based drilling fluid weighing between 9.2 and 10.0 lb/gal was used to drill the upper-hole section down to 15,700 ft. The lower-hole interval was also drilled with water-based drilling fluid with a maximum mud weight of 12.0 lb/gal.

Background

Tieback casing strings are used on many high-temperature/high-pressure (HTHP) wells designed with a production liner across the zone of interest. Typically, the length of the tieback casing string is 12,000 to 16,000 ft. A long column of cement helps provide lateral support to prevent casing buckling. Many tieback strings are installed just before installation of the completion equipment. Therefore, shortly after installation, the

tieback string may be exposed to the following conditions:

- Wellhead temperatures in excess of 300°F
- Possible fracturing treatments
- Temperature cycling during the commissioning of surface facilities

Cementing operations are normally conducted by pumping a cement slurry down the inside of a casing string and displacing the cement slurry with another fluid, forcing the cement slurry into the casing annulus. This method is commonly referred to as a forward-circulation procedure.

Another option is to pump the cement slurry using a reverse-circulation procedure. In this operation, the cement slurry is pumped down the casing annulus and returns are taken inside the casing. A reverse-circulation procedure can have several advantages, including the following:

- The entire cement slurry is not exposed to the circulating temperature at the bottom of the casing
- Multiple stages of the cement slurry with different retardation can be used
- Equivalent circulating densities (ECDs) are lower, pumping and displacing the cement slurry
- Setting-time and compressive strength can be similar over the length of the cement column

Reverse-Cementing

Based on the documented experiences of several onshore reverse foamed-cement jobs³, the following pros and cons can help determine whether a reverse-circulation job is the right option:

Pros

- Can reduce job placement time from 5 hrs to 2 hrs
- Can reduce wait-on-cement (WOC) time
- Can improve safety by avoiding foamed-cement returns to surface
- Can vary the retarder concentrations, enabling shorter cement set-times in spite of the temperature difference at the top and bottom
- Can reduce the ECD

Cons

- Pumping operations require an unconventional piping layout
- May need to hold back pressure on the tieback casing
- Cannot use wiper plugs
- Cannot use standard float equipment
- Difficult to accurately track cement height inside the casing
- May need to drill additional cement inside the tieback

Cementing Requirements

The static temperature profile may vary significantly from the top to the bottom of the cement column. Consequently, slurry for long columns is difficult to design because of the great differences in static and circulating temperatures at the top and bottom of the column. Static temperatures at some depths may be significantly less than the bottomhole circulating temperature during placement of the cement.

When determining the cement properties for an HPHT tieback, all the stresses should be considered. The stresses for the tieback on the Fairway Field well included: pressure increase due to pressure-testing of the casing to 8,000 psi, temperature increase at surface to 300°F due to production, and pressure increase due to production. The Finite Element Analysis (FEA) program⁴⁻⁵ was used to analyze the stresses on the pipe, cement sheath, and formation. The sealant (foamed cement) was expected to meet both the short-term and long-term requirements of the well. The capability of foamed cement to withstand cyclic loading was demonstrated by Goodwin and Crook.⁶

Tieback Cement Sheath Stress Modeling

Throughout the life of the well, a number of activities can stress the cement sheath and potentially cause it to fail. These activities include producing and shutting-in the well, swapping well fluids, pressure-testing, and injecting fluids. Using the FEA model, both wells in the Mobile Bay area were studied to determine whether the cement sheath would debond, crack, or plastically deform in any way from the time that the cement was placed until the well was abandoned.

The study was conducted at three locations along the tieback to determine the most critical point. Table 1 lists some of the modeling results. According to the model, the most critical point was nearest the top of the cement column.

The study also evaluated three types of cement slurries: a conventional slurry, a conventional slurry with a plastic state expansion additive to compensate for shrinkage, and a 20-quality foamed cement.

The conventional slurry failed at all points along the tieback, while the non-shrinking slurry was intact at the bottom of the tieback, but the foamed slurry remained intact along the entire tieback during all loading cases.

The mechanical properties for two of the slurries evaluated are listed in Table 2. The FEA program also produced graphical output using color to represent the results of applied stresses on the cement sheath. Figure 3 shows the output for the conventional slurry at the 2,500-ft depth, while Figure 4 shows the output for the foam slurry.

Cement Slurry Design

Foamed cement was selected for its set mechanical properties. Next, the cement slurry had to be designed to meet several criteria, including the following:

- Maximum foam stability while in the slurry state
- Adequate thickening time to place the cement
- Optimum compressive strengths along the entire annular column
- Easy mixing with the cementing unit

A one-base dry cement blend was preferred for ease in logistics and operations. Liquid retarders and foaming agents were used “on the fly” to create a “three-staged” final optimal design. The final base cement design consisted of Class H cement + crystalline silica flour + amorphous silica fume + HEC + bulk cement flow-enhancing aid.

The base slurry was designed with 5.6 gal/sk of fresh water to mix easily at a density of 16.3 lb/gal, and then foamed to a final density of 13.5 lb/gal. The test results of the design, including initial pilot tests and final blend tests, are listed in Table 3.

Crystalline silica flour was used to help prevent strength retrogression at the high bottomhole static temperatures. Amorphous silica fume and hydroxy ethyl cellulose (HEC) increased the viscosity of the cement, which in turn helped maximize the foam stability of the unset cement slurry. For foam cementing, it is critical that the nitrogen gas remain evenly dispersed and stable throughout the cement slurry. The bulk flow-enhancing aid facilitated the pneumatic transfer of the base cement from the cement boats to the rig bulk tanks prior to the job, and also the flow of cement to the cementing unit during the job.

With the reverse-circulation method, the cement slurry could be designed in stages by tapering the concentration of retarder. Cement in the upper sections of the tieback string, where less temperature is encountered and where less placement time is required, could be designed with less retarder than the cement at the bottom of the tieback. Reducing retarder concentrations in the upper sections of the cement column helped enable maximum strength development along the entire tieback annulus. A liquid retarder was injected on the fly in three stages. Retarder concentration for the leading stage was 0.13 gal/sk of cement. Stage 2 tapered the retarder concentration to 0.07 gal/sk. The third and final stage further reduced the retarder concentration to 0.04 gal/sk.

A foaming agent was used to create a stable, high-quality foam that was injected into the cement slurry on the fly. Concentration of the foaming agent was 0.14 gal/sk of cement for all stages.

Spacer Design

Turbulent flow spacers were used to help displace the light mud from the annulus. One hundred barrels of seawater were pumped, followed by seventy barrels of 13.0 lb/gal-weighted turbulent flow spacer. Fourteen barrels of the weighted spacer followed the cement job, which was then followed by mud displacement. The weighted spacers contained foamer, injected on the fly to create a stable foam interface if intermixing with the cement slurry occurred.

Casing Hardware

The casing hardware required for a job using the reverse-circulation process differs slightly from that for a forward-circulation operation. The tieback casing was run without float equipment, the displacement down the annulus did not allow the use of plugs, and because returns are taken through the casing string, no landing collar was used.

To help ensure adequate displacement efficiency in the annulus, centralization is critical. After the first job, greater centralization was applied to achieve higher displacement efficiency. The casing tieback string was centralized to maintain a minimum standoff of 65–70%. A total of 375 positive standoff centralizers were spaced out in the tieback string as shown in Figure 5.

Mixing and Pumping Operations

A continuous mix operation was chosen for mixing the cement slurry. The cementing unit contained a 25-bbl mixing tub, which serves as a very good cement slurry-averaging tank. Had the unit contained a smaller mixing tub, a separate large averaging tank would have been recommended.

Prior to the critical reverse-foamed job, the cementing unit was thoroughly inspected to help ensure proper performance. Rig bulk tanks were inspected and cleaned, and new aeration spiders were installed. This preparation resulted in a bulk delivery system that provided consistent flow of cement to the cementing unit.

All equipment used to mix the foamed-cement slurry was process-controlled. The cement was mixed using automatic density control. The nitrogen injected downstream into the base slurry was also automatically controlled by the pumping rate of the slurry. This process provided a foam uniform in quality, even as the cement slurry rate was fluctuated. Liquid retarder and foamer were also injected automatically, based upon the mix water flow rate.

For the reverse-foam cement job, numerous data were monitored and acquired. Table 4 shows the monitoring methods used for rates, volumes, pressures, and densities. Several unique measurements are specific to reverse-cementing. Critical to the success of the cement placement is the measurement of returns volumes. If the returns volume is known, the position of the cement downhole is easily and directly determined. The fluid returns are measured with a flowmeter in the returns line and also by visual measurement of returns back into the mud pits.

Also unique to a reverse-foam job is the measurement of the pressure in the returns line. This “backpressure” affects the overall system pressure, which in turn affects foam quality and density. The backpressure is not only monitored, but can be adjusted during the job through a choke system to properly follow the modeled job.

Piping Setup

An offshore reverse-circulation foam job requires a well-planned system of piping and valves. Figure 6 shows the intricate piping and valve positioning for the actual reverse cement-pumping stage. Several similar diagrams were prepared showing valve positioning for all phases of the job, including cement line-pressure testing, final cement job displacement, release-of-line pressure, and lowering of the tieback casing.

Included in the piping design was the capability to reverse all nitrified fluids from the well in case the job had to be prematurely aborted. The piping was set up to reverse the slurry to surface, inject defoamer, and discharge the slurry into a barge for disposal.

In the piping design, it was determined that the entry point of cement into the annulus during the job should be located just below the annular rams (Fig. 7). This location would help minimize “dead space” below the rams where nitrogen could break out and collect. Proper

placement of the entry point was essential in case a substantial amount of nitrogen gas existed below the blowout preventers (BOPs). The safe release of pressure from the nitrogen gas before opening the rams and lowering the tieback would be very difficult.

When pumping a reverse-circulation foamed cement, injecting into both sides of the annulus is important. Injecting into both sides helps prevent channeling down one side of the annulus.

Safety was the overriding factor in the design and layout of the piping for the reverse-foam job. Lines to the rig floor and to the wellhead were positioned away from the V-door and driller’s shack to allow safe access during the job and safe evacuation routes.

Safety briefing areas were designated away from high-pressure lines. Figure 8 shows a layout of the drilling rig with equipment, high-pressure lines, and designated safe areas. This information was provided to all personnel during prejob safety meetings. Because the job would use energized nitrified cement slurry, cryogenic safety training was also provided to all rig personnel prior to the job.

Contingency Planning

Extensive contingency planning preceded the job. Contingency plans provided operational guidelines in the event of equipment failures or material supply interruptions. The required cement column length was a key factor in developing the contingencies. When the minimum volume of cement required for adequate casing support was determined, all possible contingencies were written, distributed, and reviewed. An example of the contingency planning is shown in Table 5.

Communication/Teamwork

Project management is key to the success of a reverse foamed-cementing job. Clear communication and task assignment by the team throughout planning and implementation is vital.

During the planning phases, several meetings involving the operator, the service company, the rig personnel, and the support team were convened to assign tasks, set timetables, review procedures and contingencies, and discuss logistics. The final project design and procedures were documented and distributed, then reviewed and approved by all parties.

During the job, communication passed through a single command center to help prevent confusion. All personnel involved in the job were equipped with radio headsets. From central control, all piping and valving decisions were relayed to a single manifold operator. All

monitoring, decision-making, and communication with the operator, the rigfloor, and the cementing unit was conducted through this command center.

Job Execution

After pressure-testing all lines, the well was reverse-circulated with drilling fluid for several hours to clean the wellbore and to determine system backpressures at various rates. A minimum backpressure was required by the job design to control foam quality over the entire length of the cement column.

The fluids were then pumped by reverse-circulation, as shown in Table 6.

Job Data

Cement slurry rates, pressures, and densities are shown in Figure 12. The following points of interest are shown in the job data plot:

- A—Reverse-foamed job started. Seawater spacer pumped.
- B—Weighted spacer pumped at a density of 13.0 lb/gal.
- C—Slurry density, mixed with automatic density control, was consistent at 16.3 lb/gal throughout the job.
- D—The only variation in cement slurry density occurred during the switching from one bulk tank to another. Point D shows that density dropped when cement delivery was temporarily interrupted, but was soon regained.
- E—Cement was mixed and pumped at a consistent liquid rate of 4 bbl/min. Nitrogen injection increased the total downhole rate to approximately 5 bbl/min.
- F—Returns rate was measured by an inline turbine flowmeter. This measurement was crucial to determine accurate placement of cement inside the tieback string.
- G—This pump pressure, measured at the entry of the BOPs, ranged from 1,600–800 psi during the pumping of cement. Surface pressure dropped to 300 psi during displacement. When foamed slurry began to rise inside the tieback, the pressure increased to a final 850 psi.
- H—Backpressure during the job started at 740 psi and slowly declined throughout the job to approximately 400 psi. Returns during the job closely followed prejob predicted rates. Therefore, backpressure was not manipulated by the choke system during the job.
- I—Cement pumping completed. Began displacing cement at 10 bbl/min with rig pumps.

- J—Returns rate began to increase rapidly, indicating that foamed cement was being lifted inside the tieback. As the foam rises, it expands, and increases the returns rate out. The job could have been stopped, but additional cement displacement was pumped as a safety factor to ensure quality cement inside the tieback string.
- K—Job complete. Pressure is released from the injection side.
- L—The tieback was lowered into the tieback receptacle. As it was lowered, trapped fluids were compressed and pressure inside the tieback immediately rose from 300 to 900 psi. Consequently, the returns line was opened and allowed to flow as the tieback was lowered. When the tieback was landed, all flows stopped.

Throughout the job, mixing-water volumes and cement-slurry volumes were compared with the returns volumes as measured by the inline flowmeter and also by observing the mud pit returns. Table 7 lists the recorded volumes during the job compared to the volumes predicted by prejob computer simulations. Predicted volumes were very close to actual volumes. At the end of the job, a total of 1,178 bbl of returns was recorded, only 16 bbl more than the predicted volume.

Job Results

All operations for the reverse-circulation foamed job were conducted safely, without spills, and according to plan. After the cement was displaced, pressure was released and the tieback was successfully lowered into the tieback receptacle and landed out in the surface wellhead.

During completion operations, hard cement was tagged at 12,005 ft, approximately 3,000 ft inside the tieback. Based on flow returns, the predicted tag depth was 12,386 ft, only 381 ft from actual.

Conclusions

Based on the experience of the Fairway Field well, the following conclusions can be made:

- Accurate placement of foamed cement using reverse-circulation can be achieved in an offshore environment.
- The injection point of the foamed cement should be directly below a casing ram to help minimize the possibility of trapped pressure. If trapped pressure occurs, attempt to bleed it off *slowly*. A small volume of foamed-cement slurry trapped above the injection point quickly expands and can create an HSE hazard if pressure is relieved immediately (by opening the casing rams).

- During casing tieback operations, there is a sense of urgency to land out the casing after the cement slurry has been placed in the annulus. However, time is required to analyze and bleed off pressures as needed before lowering the tieback. This process may require that the casing string remain static with the foamed-cement slurry in the annulus for 15–20 min. Cement slurries should be designed with low, nonprogressive gel strengths to remain fluid during this period.
- A downhole system is needed to indicate when the cement slurry (or any given fluid) passes a certain point in the casing string. During the displacement, being able to verify when the cement enters the inside of the casing would be helpful. Coupling that system with a downhole shut-off device, similar to a float valve, could reduce the possibility of leaving an excessive volume of cement inside the tieback casing string.
- Reverse-circulation, foamed-cement job design can be simplified from the process described in this paper. Use of the drilling rig manifold system could reduce the amount of piping and equipment used in a job. Drilling rig pit volume-monitoring equipment, if properly calibrated, can provide an accurate measure of returns volume into the rig pit system.
- Assessing the probability of circulating foamed cement to surface and having to discharge such a slurry should be considered. The assessment should include the likelihood of failing to mix the cement slurry as planned and the impact that such a slurry could have during the life of the well. There should be a clear understanding before the job of a “critical or minimum volume” of cement slurry required to meet the well’s objectives. Aborting the job after reaching this critical volume should not be considered.
- Drift in electronic gauges should be considered with time and temperature changes in the equipment during pumping operations. An 80- to 150-psi drift was observed using 15,000-psi pressure transducers. This drift raised a safety issue after pumping operations were completed because there appeared to be pressure on the piping system that could not be bled off. The pressure rating of the gauges should closely match the maximum anticipated pressure that the gauge will be exposed to during the job.

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Table 1—Cement Sheath Stress Analysis at Tieback TOC (2,500 ft)

Phase	Load	Conventional Cement	Foam Cement
Cement hydration	Cement 1 = 4 % shrinkage Cement 2 = 0 % shrinkage	Debonding	Intact
Pressure test	8,000 psi	Plastic deformation	Intact
Change fluid	12.0 lb/gal drilling fluid to seawater	Debonding	Intact
Production	Gas producer at 45 MM ft ³ /D	Failed during hydration	Intact

Table 2—Tieback Cement Mechanical Properties Used for FEA

Property	Conventional Cement	Foam Cement
Young's Modulus:	1.2	0.8
Poisson's Ratio:	0.2	0.1
Tensile Strength:	300	250
Hydration Volume:	-4%	0%

Table 3—Pilot and Final Blend Test Results*

Temperature (°F)	Type (BHST/BHCT)	Depth TVD/MD (ft)	Retarder (gal/100 sk)	Slurry Tested	TTT (hr:min)	Compressive Strength	
						12 hr (psi)	24 hr (psi)
BHST/BHCT Condition 3							
140	BHCT	4,000	3	Base (unfoamed)	3:21		
150	BHST	4,000	3	Foamed		80	910
Blend Test	BHCT	4,000	3	Base (unfoamed)	3:38		
BHST/BHCT Condition 2							
186	BHST	8,000	8	Foamed		50	450
170	BHCT	8,000	8	Base (unfoamed)	5:13		
Location Test	BHCT	8,000	8	Base (unfoamed)	6:04		
BHST/BHCT Condition 1							
230	BHCT	15195/15720	13	Base (unfoamed)		1110	2420
275	BHST	15195/15720	13	Foamed		410	1160
230	BHCT	15195/15720	13	Base (unfoamed)	8:11		
Blend Test	BHCT	15195/15720	13	Base (unfoamed)	8:28		

*Density=13.5 lb/gal, foamed; Yield=1.47 ft³/sk, base unfoamed; Total Liquid=5.6 gal/sk, base unfoamed

Table 4—Data Acquisition and Job Monitoring Plan^a

Rates/Volumes	Stroke Counter	1-in. Flowmeter	2-in. Flowmeter	3-in. Flowmeter	Pressure Transducer	Visual	Densometer	Pressurized Mud Scale
Cement Pump 1	1							
Cement Pump 1	1							
Total Liquid Rate				1 ^d				
Measuring Tanks						1		
Water				1		1		
Foamer	1					1		
Foamer		1						
Fluid Position			1			1		
Retarder	1					1		
Returns 1			1 ^b					
Returns 2			1 ^c			1		
Nitrogen 1	1							
Nitrogen 2	1							
Total Nitrogen		1						
Pressure	Stroke Counter	1-in. Flowmeter	2-in. Flowmeter	3-in. Flowmeter	Pressure Transducer	Visual	Densometer	Pressurized Mud Scale
Cement Pump 1					1			
Cement Pump 2					1			
Return Pressure					1 ^e			
Annulus Pressure					1 ^e			
Nitrogen Pressure					1			
Density	Stroke Counter	1-in. Flowmeter	2-in. Flowmeter	3-in. Flowmeter	Pressure Transducer	Visual	Densometer	Pressurized Mud Scale
Downhole Density							1	
Cement Tub							1	1

^aElectronic sensors data was monitored and stored in computer data acquisition system

^bOne 2-in. flowmeter needed for the job

^cOne 2-in. flowmeter and one MC-II needed for the job

^dOne 3-in. flowmeter needed for the job

^eTwo pressure transducers needed for the job

Table 5—Sample Contingency Planning for Potential Job-Terminating Events, Ex: Critical Material Delivery Failure

Condition	Effect	Options/Actions
Cement delivery problems	Inability to mix cement slurry to proper density and inability to pump cement into the well	If bulk delivery cannot be restored within 15 minutes, try one of the following options: If cement volume pumped is <i>greater</i> than or <i>equal</i> to minimum required volume: – Displace cement If cement volume pumped is <i>less</i> than minimum required volume: – Circulate all cement out
Loss of mix water supply	Inability to mix slurry and pump cement into the well	If water supply cannot be restored within 15 minutes, try one of the following options: If cement volume pumped is <i>greater</i> than or <i>equal</i> to minimum required volume: – Displace cement If cement volume pumped is <i>less</i> than minimum required volume: – Circulate all cement out

Table 6—Reverse-Circulation Job, Pumping Schedule

Stage	Volume (bbls)	Density (ppg)	Fluid
1	100	8.54	Seawater spacer
2	70	13	Weighted spacer with surfactant
3	295	13.5	Foamed cement with 0.13 gal/sk
4	428	13.5	Foamed cement with 0.08 retarder
5	103	13.5	Foamed cement with 0.03 retarder
6	14	13	Weighted spacer with surfactant
7	254	12	Water base drilling fluid

Table 7—Comparison of Predicted vs. Actual Returns During Reverse-Circulation Job*

Mix Water Volume (bbl)	Liquid Volume In Predicted (bbl)	Liquid Volume In Flowmeter-Measured (bbl)	Total Volume Out Predicted (bbl)	Total Volume Out Flowmeter-Measured (bbl)	Total Volume Out Measured in Mud Pits (bbl)
50	100	101	186	170	138
80	161	151	281	252	187
100	201	190	338	320	n/a
131	264	248	422	399	322
150	303	281	472	449	n/a
167	336	310	514	485	399
200	402	387	616	589	n/a
227	458	425	659	637	562
263	530	483	734	705	629
274	552	524	760	751	n/a
300	605	571	810	802	680
331	666	648	895	906	n/a
349	703	691	947	972	n/a
406	818	n/a	1032	1055	n/a
431	868	n/a	1067	1078	n/a
456	918	n/a	1107	1109	n/a
472	950	n/a	1162	1178	1134

*Gray bar indicates end of pumping cement and beginning of displacement.

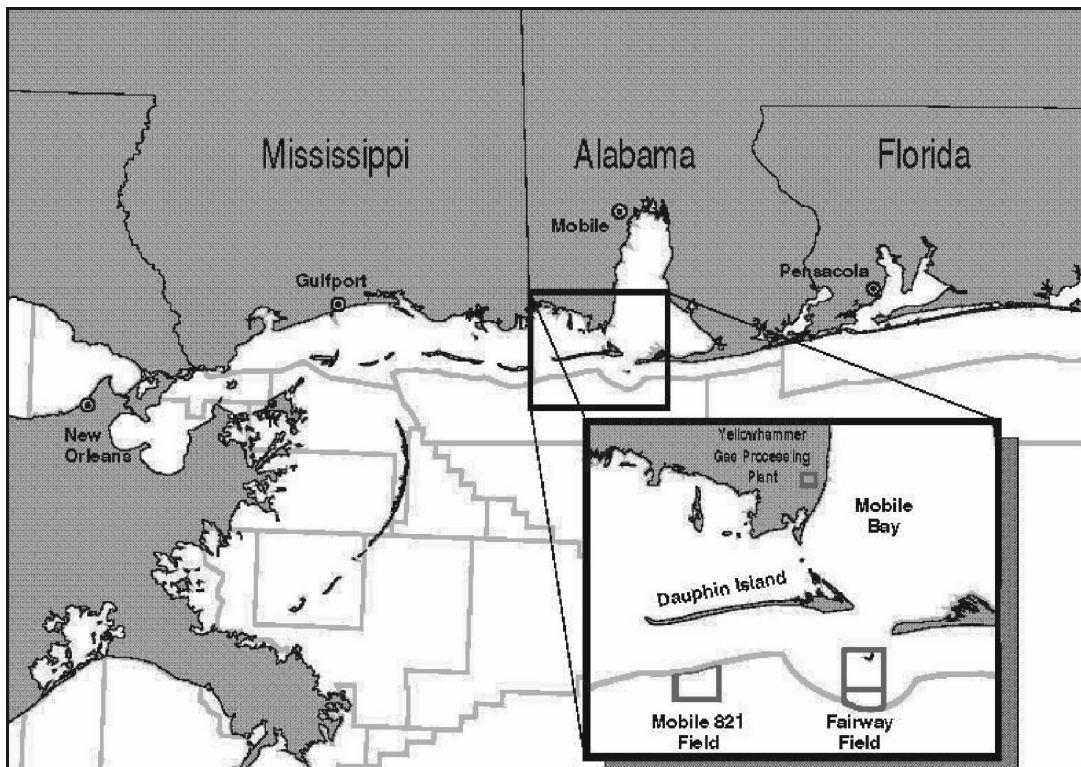


Fig. 1—Location of Mobile 821 and Fairway Fields

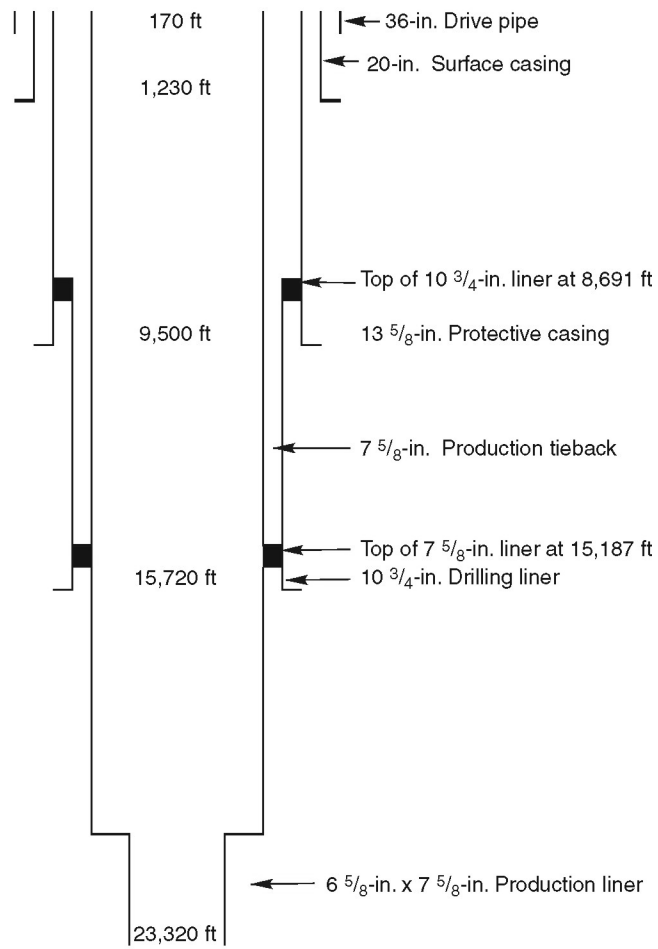


Fig. 2—Well schematic, Fairway Field

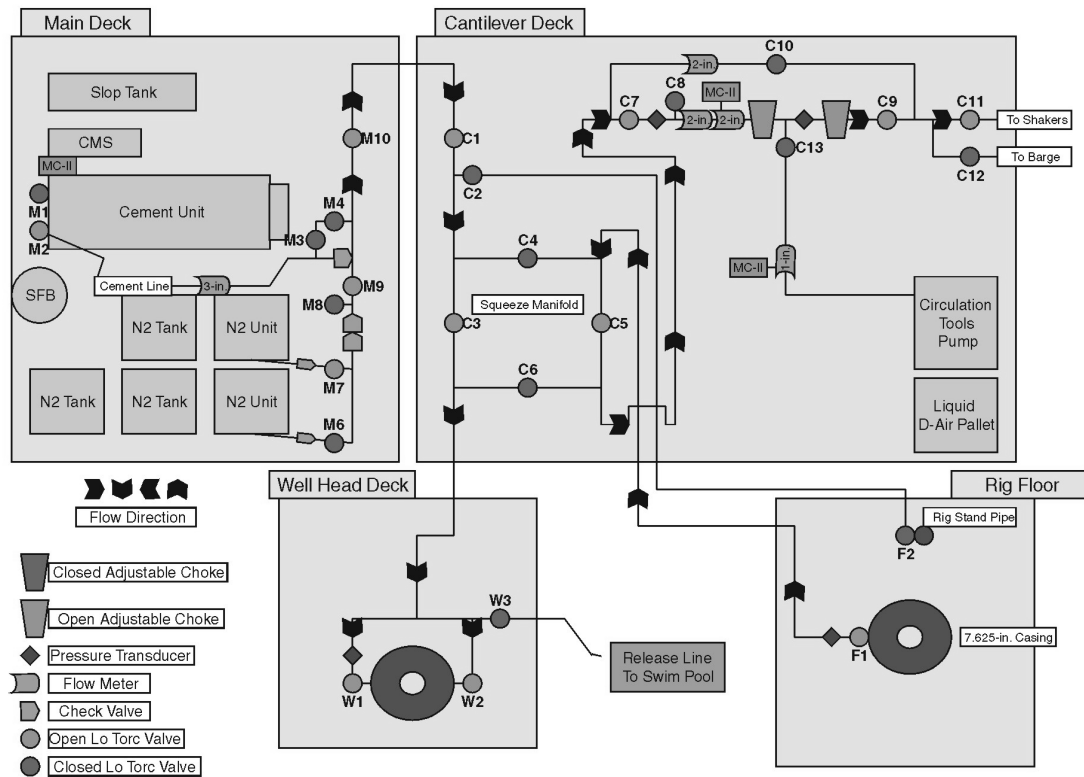


Fig. 6—Offshore reverse-circulation foam job with intricate piping and valve positioning

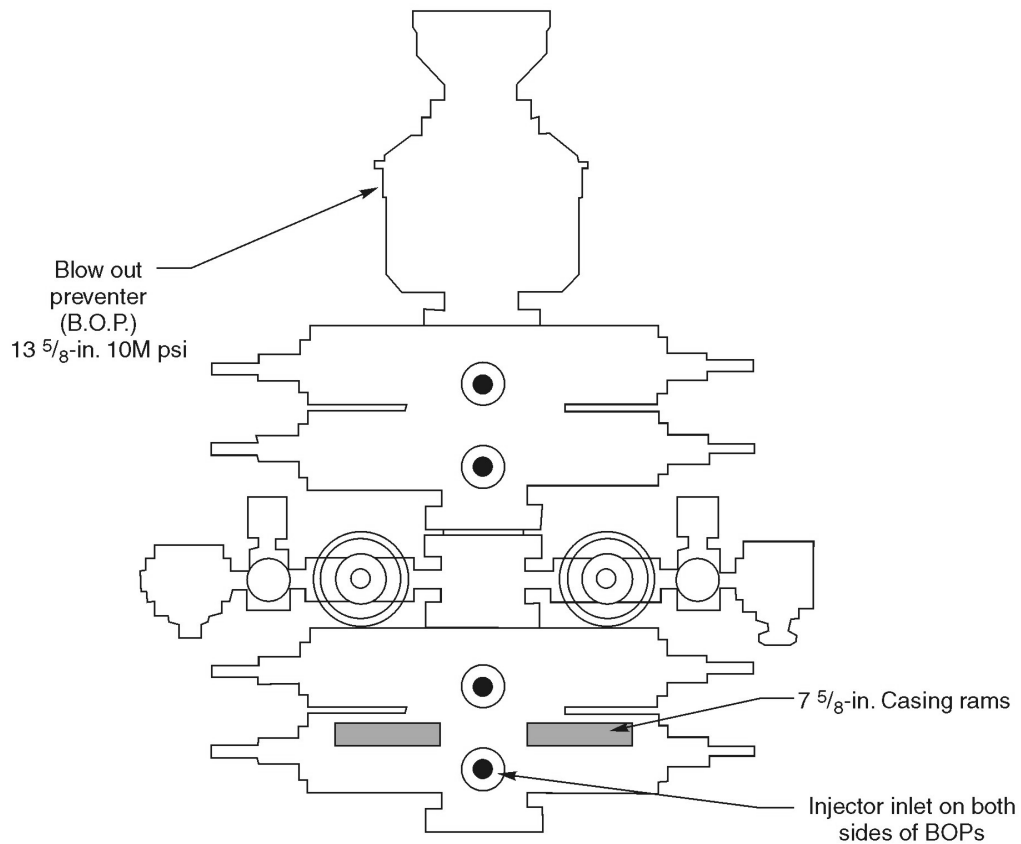


Fig. 7—Entry point of cement into the annulus during the job located just below the rams

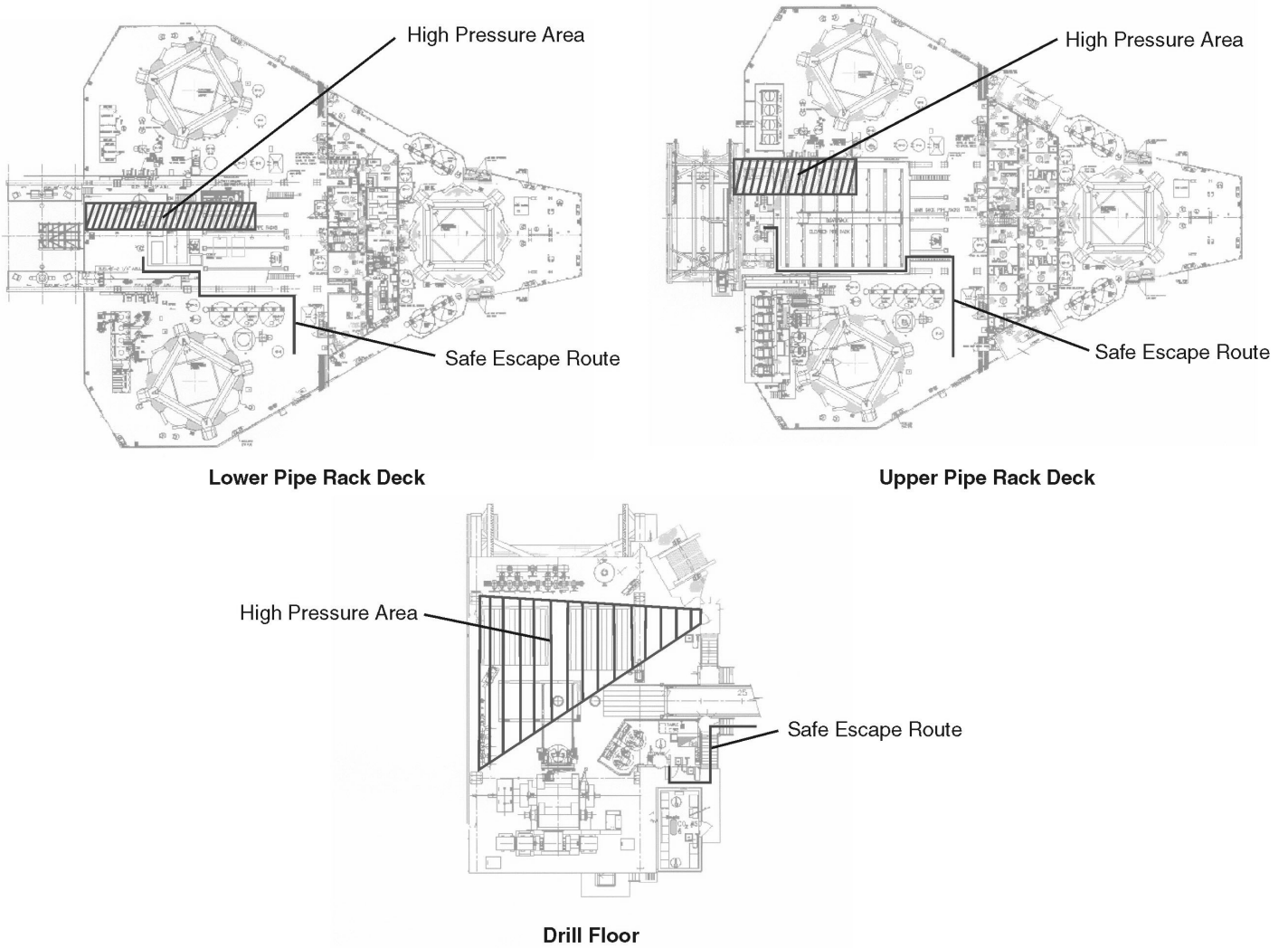


Fig. 8—Rig floor layout with safety and hazard areas

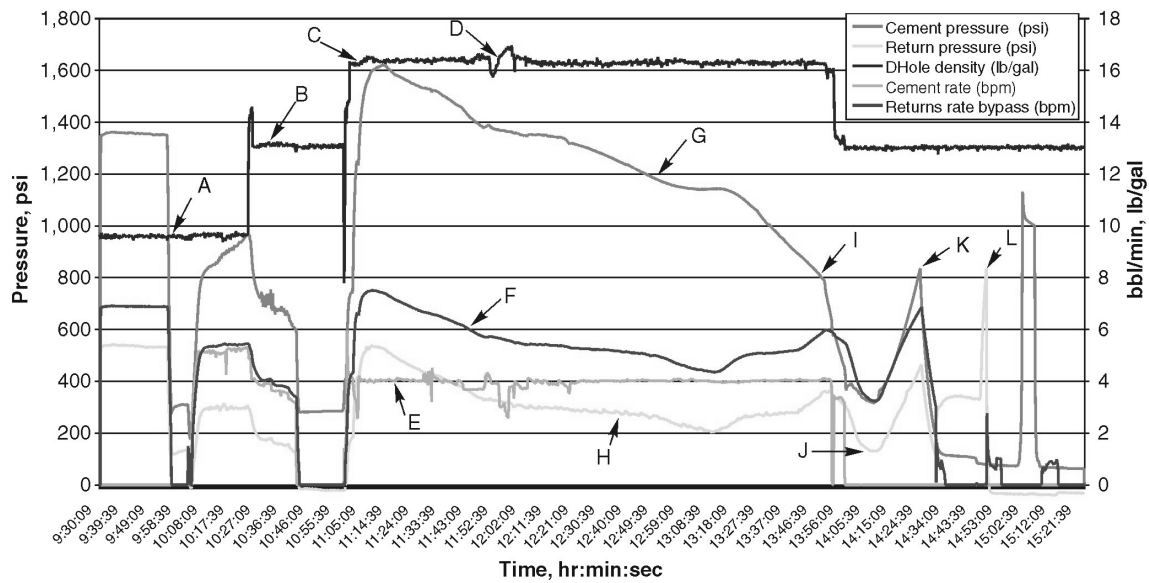


Fig. 9—Reverse foam-circulation tieback job data