Maersk Oil & Gas A/S began drilling horizontal wells in the Dan field in 1987 with the primary goal of improving productivity in the low-permeability chalk. A feasibility study concluded that a matrix-acidized horizontal well would yield a productivity equal to or slightly better than that of a successfully propped, hydraulically fractured conventional well, albeit at a higher cost.[1] Therefore, to make horizontal wells economically attractive, fracture stimulating multiple zones in the drainhole section would be necessary. Before the use of this new technique, three Dan field horizontal wells—Wells MFB-14, MFB-15, and MFB-13—were completed with multiple fracture stimulation treatments. Production experience from these three horizontal wells confirmed that production increases by a factor of three to four over that of a conventional well. Thus, the decision was made that further field development would be based mainly on multiple fractured stimulated horizontal wells.

Completion Experience With Existing Horizontal Wells. Successful liner installation and cementation is considered a prerequisite to ensure adequate zonal isolation for multiple fracture treatments in horizontal wells. The radius of curvature for both the short- and medium-radius methods (33 to 50 ft and 300 ft, respectively) would make successful liner cementation difficult. For this reason, the long-radius directional drilling method was considered to be the most attractive option.

Although the first horizontal well (Well MFB-14) was equipped with a 5½-in. liner across the reservoir, 7-in. liners have been installed in subsequent wells to allow more flexibility in the selection of perforating and stimulation tools.

Because an initial concern was that the annular area between the 7-in. liner and the 8½-in.-diameter hole would be insufficient for a good cementation job, 6⅝-in. liners were considered as an option. A Cement Evaluation Tool[SM], Variable Density Log[SM], and gamma ray and casing-collar locator logs run in all Dan field horizontal wells indicated that zonal isolation had been achieved with the 7-in. liners that had been well centralized and rotated during cementation. This was confirmed during execution of fracturing jobs where no communication between individual fractures was observed.

Previous Perforating/Stimulating Techniques. The following abbreviated history of completion systems used in previous Dan horizontal wells corroborates the need for an improved completion system for multiple stimulated horizontal wells.

Well MFB-14 was perforated and stimulated with the following procedure (see **Fig. 1**).

1. The zone was perforated and stimulated with a conventional drillstem test string.
2. After the well was killed with brine and losses were cured with lost-circulation materials, a bridge plug was set above the zone.
3. The next zone was perforated, stimulated, and tested.
4. After the well was killed, the bridge plug was milled and pushed to bottom, and a new bridge plug was installed above the latest set of perforations, after which a new zone could be perforated and stimulated.

This procedure required three trips to stimulate one zone. This, together with problems with curing losses and gains experienced when the bridge plugs were milled and pushed to bottom, resulted in an excessive total stimulation time.

To reduce time during the perforating and stimulating operations, a straddle packer assembly (**Fig. 2**) was used successfully on the second horizontal well, Well MFB-15. This well was stimulated with acid without proppant. To maintain well control during tripping, it was necessary to flow each zone after the stimulation because of the 300- to 400-psi supercharging from the stimulation fluids.

A new packer assembly was designed for stimulation of Well MFB-13. The objective of the new design was to enable isolation of the fractured zone immediately after stimulation to prevent the gain/loss situation experienced in Well MFB-15. This would be achieved by placing the retrievable bridge plug above the last treated interval while picking up a new tubing-conveyed perforating (TCP) assembly. **Fig. 3** shows this tool string. Two different bridge plugs, one inflatable and the other mechanical, were used, with some operational problems.

Development of Method

Cost and Performance Objectives. Drilling and completion of Wells MFB-14, MFB-15, and MFB-13 were finalized in mid-1988. An operations review showed that the scope for significantly improving drilling time was limited, but there was a potential for significantly reducing completion time and associated costs. Therefore, the decision was made to design completion tools/techniques for horizontal wells with the following objectives: (1) to reduce stimulation and completion time for both acid fracturing and propped hydraulic fracturing; (2) to reduce or eliminate losses of expensive completion fluids and thereby improve well control during completion operations; (3) to allow selective restimulation of the individual zones without a drilling rig or workover hoist; and (4) to permit isolation of or to shut off zones producing excessive amounts of gas.

Completion System Development. With a thorough understanding of the desired completion system characteristics, the designers conceived numerous alternatives, ranging from modifications of existing techniques to novel methods that would require extensive development. Four of the most viable alternatives were developed to a degree sufficient to project the performances and characteristics of the systems. For each concept, a proposed completion program was generated that described each required operational step in sequential order. A performance matrix comparing the relative merits and disadvantages of each system was also produced. Finally, an economic analysis covering total projected costs for each

*Now at The Western Co.

Fig. 1—Stimulation with millable bridge plugs.

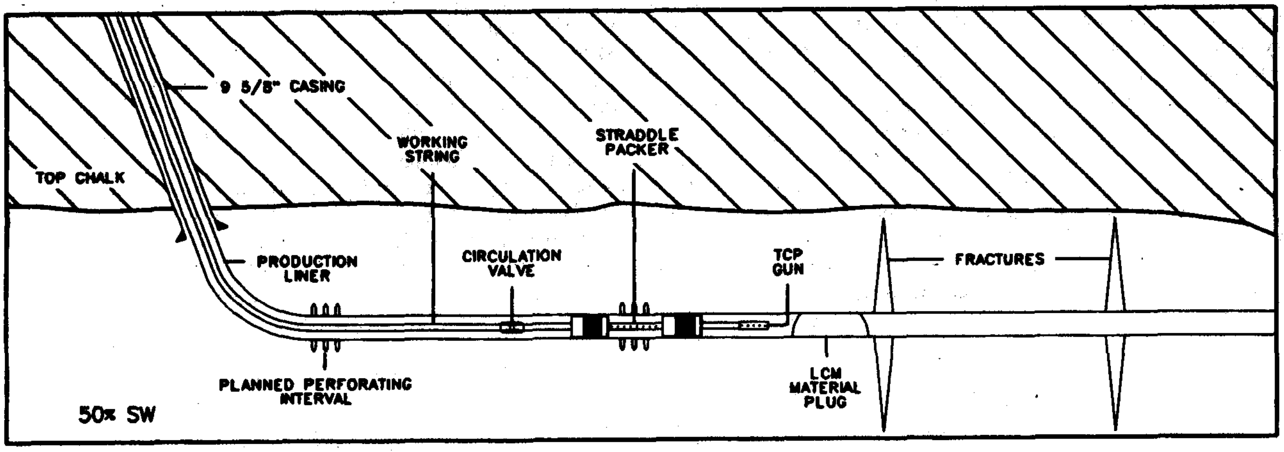

Fig. 2—Stimulation with straddle packer.

option was conducted. This analysis included, but was not limited to, hardware procurement, expense of performing each operation, and potential cost of fluid losses. The analysis indicated that the option selected addressed each performance objective, offered total cost advantages, and was based on proven technology. The option selected was the perforate, stimulate, and isolate (PSI) system.

PSI System Description

The completion system selected for development was designed to permit each interval to be perforated, stimulated, and isolated in a single workstring trip. This system consists of three basic assemblies: a permanent sump packer with bull-plugged bottom (Fig. 4), a downhole assembly for isolating each interval after treating and permitting selective production or stimulation (Fig. 5), and a service assembly for perforating and stimulation operations (Fig. 6).

The downhole and service assemblies are made up with the 2⅞-in. concentric workstring and TCP gun assembly installed concentrically inside the downhole assembly (see Fig. 7). These two components are run into the well simultaneously. Following perforation and stimulation operations, the downhole assembly is positioned and set in a manner to isolate the perforations; then the service assembly is retrieved from the wellbore.

After all zones are isolated and the production tubing string is installed, a coiled-tubing-conveyed manipulation tool string is run in to open the sliding sleeves. The tool string can be run at any time in the future to close off any zone or to reopen a zone that was previously closed. The tool string includes a backflow valve, an emergency release device, and a washing device to clean out the sliding sleeves before they are moved.

Downhole Assembly. The downhole assembly consists of three main parts (see Fig. 5). The first is a locator seal assembly used to provide pressure integrity between the sump packer and the downhole assembly. The second component is a sliding sleeve used to provide selective production control. The third is a hydraulically set, retrievable isolation packer.

A 4½-in.-OD, 12.6-lbf/ft L-80 tubing with premium threads is made up between the seal assembly and the sliding sleeve. This section typically is 20 to 80 ft long.

The sliding sleeve, which is run in the closed position, contains a sleeve valve that can be opened by shifting upward and closed by shifting downward with a coiled-tubing-conveyed manipulation tool string.

An additional length of 4½-in.-OD, 12.6 lbf/ft L-80 tubing with premium threads is made up between the sliding sleeve and the isolation packer. The length of this section is governed by interval spacing, but it typically ranges from 200 to 400 ft.

The last component in the downhole assembly is a hydraulically set, retrievable isolation packer. This packer contains a sealbore that will accept seal assemblies. The isolation packer's setting piston is hydraulically balanced to prevent presetting. It cannot be set until the locator seal assembly has been stabbed into the sump packer.

Service Assembly. The service assembly contains five main components (Fig. 6). The lowermost consists of 20-ft-long, 3⅛- or 3⅜-in.-OD TCP guns and firing head. The firing head is actuated by hydraulic pressure. After actuating, there is a time delay before detonation to permit underbalanced perforating if desired.

The second component is a mechanism that automatically retracts the TCP guns and firing head to a position inside the downhole

Fig. 3—Stimulation with retrievable bridge plugs.

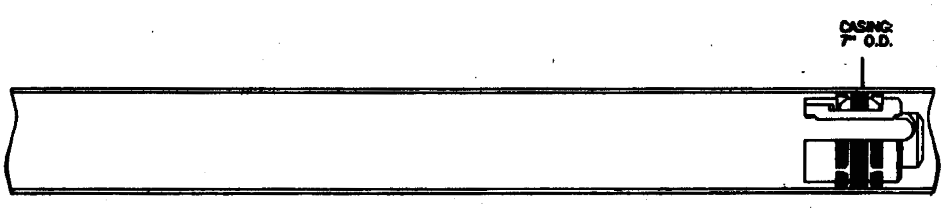

Fig. 4—Setting sump packer.

assembly after perforating. The TCP guns are retracted to allow full circulation and thus to avoid sticking problems should a premature screenout occur during fracturing.

The third component is a circulation device that allows fluid to flow from the workstring ID through the annular space around the perforating guns and into the lower casing annulus.

A length of 2⅞-in.-OD concentric workstring is used to separate the lower three service assembly components from the upper components. This workstring is also used to space the TCP guns, firing head, and gun retractor so that the TCP guns are positioned below the seal assembly after the downhole and service assemblies are connected.

The fourth component in the service assembly is the disconnect sub. It is used to make a pressure-tight, rotationally locked, mechanical connection between the service assembly and the downhole assembly. The upper end of the 2⅞-in. tubing is suspended from the disconnect sub. The two assemblies are disconnected with 30,000 lbm tension.

The fifth component is a mechanically operated stimulation packer whose design is based on standard compression-set squeeze tools. The conventional rotational control system used during setting and releasing operations was replaced by an automatic J-slot control system, which is operated with 2½ ft of reciprocation. This packer is run immediately above the disconnect sub and is attached directly to the workstring.

Operational Procedures. The basic operational procedures used with this completion system are as follows.

1. Run the bull-plugged sump packer on drillpipe and set it hydraulically at a point below the bottom interval (see Fig. 4). Pull the drillpipe and setting tool.
2. Make up the downhole assembly and temporarily suspend it from the rotary table.

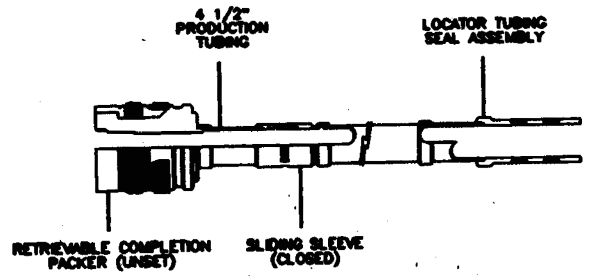

Fig. 5—Downhole assembly.

3. With a gravel-pack screen-handling table (false rotary table), run the lower portion of the service assembly through the downhole assembly ID. Run the service assembly until the disconnect sub can be made up into the top of the downhole assembly's isolation packer. The TCP guns will be spaced below the locator seal assembly at this time.
4. Run the combined assemblies to perforating depth (see Fig. 7) and set the stimulation packer by picking up 2½ ft at the packer and then slacking off 10,000 lbm.
5. Pressure the workstring to actuate the TCP guns. Guns will automatically retract after firing (see Fig. 8).
6. Stimulate according to the program (Fig. 9).
7. Pick up and release the stimulation packer. Establish reverse circulation and slack off to remove any proppant remaining inside the casing (Fig. 10).
8. Stab the seal assembly into the sump packer and pressure the workstring to 6,000 psi to set the isolation packer (see Fig. 11).
9. Bleed the pressure and pick up the workstring 30,000 lbm over string weight to disconnect the service assembly from the downhole assembly (Fig. 12). Retrieve the service assembly.

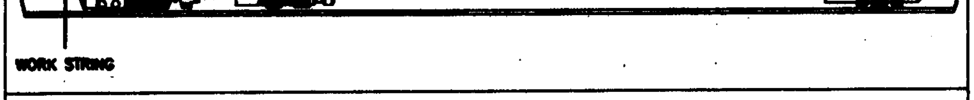

Fig. 7—Running in hole.

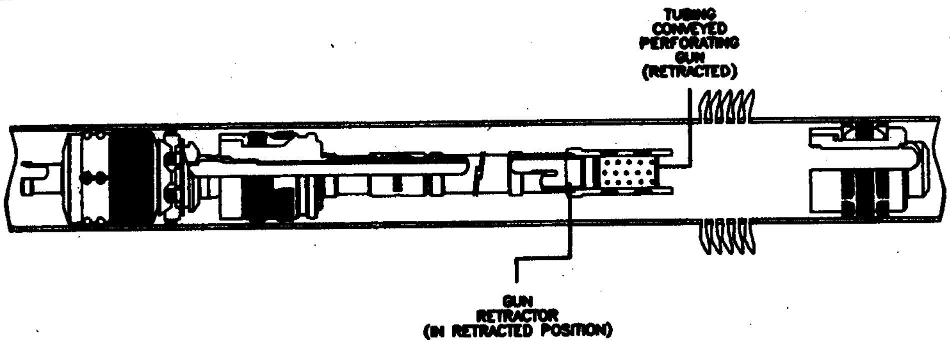

Fig. 8—Perforated.

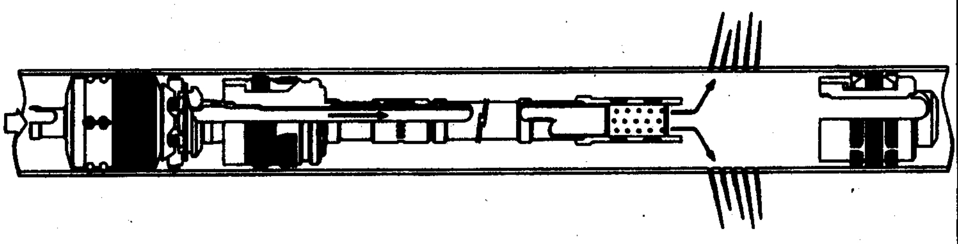

Fig. 9—Stimulating.

10. Repeat Steps 2 through 9 until all intervals have been perforated, stimulated, and isolated by stacking the required number of downhole assemblies on top of one another.

11. Make up and run production tubing and completion equipment as required. Land the production-tubing seal assembly in the sealbore of the uppermost isolation packer.

12. Run and land the tubing hanger. Make up the wellhead.

Sliding-Sleeve Manipulation. The sliding sleeves are shifted open to commingle the stimulated zones with a shifting tool carried on coiled tubing. Before the sliding sleeves are shifted, a separate coiled-tubing run is made to wash out any debris that may have accumulated in the sliding-sleeve profiles during completion.

1. Wash run. Run in the hole, maintaining circulation until just above the first sliding sleeve. Increase the pump rate to about 1 bbl/min and continue down to bottom. Then pull out, continuing to wash until out of the horizontal section.

2. Opening the sliding sleeves. Run down the vertical section of the well, maintaining sufficient pressure to allow circulation. Before the horizontal section is reached, increase the pump rate to about 1 bbl/min and continue down to total depth (TD). Pull up to the first sliding sleeve until the shifting tool engages; then continue pulling to open the sleeve. After a few seconds, the weight indicator will slowly drop off, indicating that the sliding sleeve is opening. Repeat this procedure at each sliding sleeve until all sliding sleeves are open.

Summary of Component and System Tests. It is standard practice to test new equipment thoroughly before introduction in the field. The first problem encountered during test preparation of the PSI system was that all the test facilities were designed for vertical completions. Simulation of horizontal well conditions required the fabrication of a 7-in.-casing horizontal test fixture with adequate

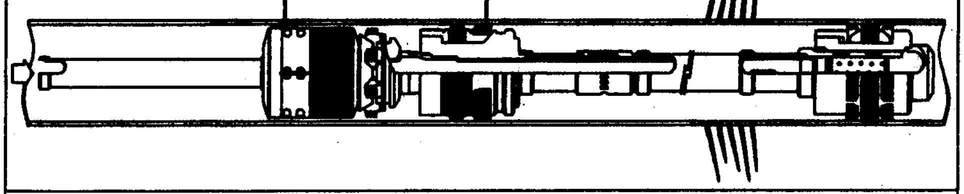

Fig. 11—Setting completion packer.

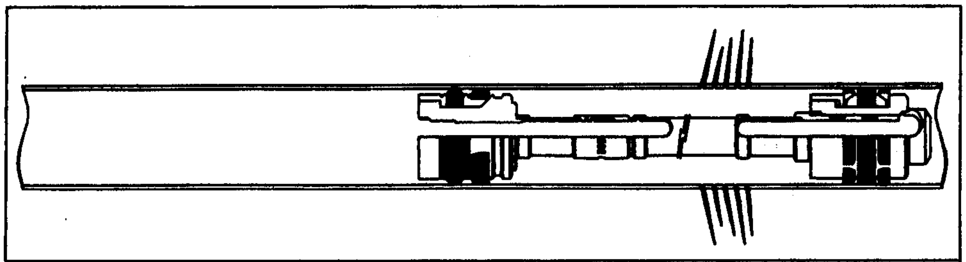

Fig. 12—Isolated with workstring removed.

space around it for running tools in and out of the fixture. This particular fixture did not include a curved section to simulate a build angle because this completion was to have a maximum build of only 6°/100 ft. The 7-in. test fixture was about 120 ft long. A hydraulic manipulator was made up to one end of the casing, with a test cap at the opposite end. The hydraulic manipulator was a long-stroke hydraulically actuated piston to provide back-and-forth motion of the components in the PSI system. The test cap and hydraulic manipulator allowed application of annulus or tubing pressure to simulate downhole conditions. The hydraulic manipulator also allowed simulation of the application of set-down weight or pickup tension from the rig floor.

Component Tests.

1. The service packer was set and released in the horizontal position. An 8,000-psi pressure test at ambient temperature and 220°F was performed.
2. The isolation packer was set, pressure tested to 7,500 psi at ambient temperature and 220°F, and retrieved.
3. Swab-off tests to determine circulation limits were performed on both packers.
4. The automatic gun retractor was actuated with 5,000-psi nitrogen as the driving medium.

Complete PSI System Tests With the Horizontal Test Fixture.

1. Set bull-plugged sump packer on a hydraulic setting tool.
2. Made up the entire assembly for one zone (see Fig. 7) with only one joint of 4½-in. tubing.
3. Set the service packer.
4. Pressure tested to 5,000 psi from above.
5. Simulated gun detonation and actuated gun retractor.
6. Simulated screenout conditions against the service packer by pressuring tubing to 7,500 psi.
7. Released service packer.
8. Stroked hydraulic actuator in to land locator seal assembly in sump packer, which was set in the bottom of the test fixture.
9. Pressure tested the upper annulus to 2,000 psi to verify seal integrity.
10. Set the isolation packer.
11. Pressure tested the isolation packer to 7,500 psi both above and below.
12. Pulled disconnect sub from the isolation packer and removed the service assembly.
13. Shifted the sliding sleeve open and then closed it.
14. Released the isolation packer with the retrieving tool and pulled the isolation string from the fixture.

As a result of these tests, the equipment was deemed ready for field runs in nonpropped stimulation applications.

A sand-slurry fracture test of the equipment was also conducted to evaluate the suitability of the equipment in situations where proppant might be required. Tools were assembled and installed in the 7-in.-casing horizontal test fixture. The slurry was circulated through the tools until a total of about 600,000 lbm of sand was pumped at a rate of 30 bbl/min through the test fixture. Fresh water was then circulated through the fixture to remove most of the sand. The equipment assembly was then pulled from the 7-in. casing. Examination of the tools indicated that turbulence caused erosion around the holes and joints over which the slurry had passed.

It was concluded that some special attention must be given to these areas before this system could be used to conduct sand fracturing operations in one trip per zone. Sand fracturing operations currently must be performed with the PSI system by perforating in one trip and running the service (less TCP assembly and gun retractor) and downhole assemblies in a second trip on drillpipe.

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