Openhole multistage fracturing boosts Saudi Arabia gas well rates

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Openhole multistage (OHMS) fracturing has improved gas production rates and recovery from moderate to tight reservoirs in Saudi Arabia. To date, 17 OHMS fracturing assemblies have been installed in deep gas carbonate and sandstone wells in southern area gas fields. Of these, 14 wells have been stimulated (acid or proppant fractured) and flowed back.

Most of these wells have responded positively and are excellent producers (>20 MMscfd). Some showed average results, 8-12 MMscfd, and a few, completed in tight reservoirs, produced at relatively low rates (<3 MMscfd) and lacked sufficient wellhead pressure to be connected to the production grid.

Some important factors affecting the results of OHMS fracturing include formation properties, completion liner size, packer types, number and size of stimulation stages, treatment types, well azimuth, and fluids pumped.

Although various well and reservoir characteristics influence well productivity, the completion type is critical and plays a central role in successful stimulation treatments and final production rates.
Companies have deployed OHMS assemblies extensively in North America, but they are relatively new in the Middle East because conventional Middle East horizontal wells usually produce at high rates and only require small stimulation treatments to clean up the near wellbore from drilling induced damage.

The tight gas zones in Saudi Arabia typically lie deeper and are more complex with higher temperatures and pressures than most tight gas zones in North America and therefore require much more accuracy and precision in applying OHMS technology.

**OHMS systems**

Conventional vertical wells limit the exposure between the wellbore and producing intervals and this in turn limits production capability. Even hydraulic fracturing of a vertical well does not necessarily augment production for sustaining long-term flow rates due in tighter rock.

By dramatically increasing the contact area with the producing interval, directional drilling with slanted or near-horizontal wells held promise to increase production. Subsequently, it became apparent that this longer wellbore contact alone was insufficient in some cases to provide the expected production increases. These wells, therefore, require stimulation treatments for reaching the production targets.

Saudi Aramco’s gas reservoir management division recently completed a comprehensive study on critical factors for increasing productivity based on well configuration and reservoir properties. Fig. 1 illustrates the productivity increase that one can expect between horizontal and vertical wells and between fractured and openhole horizontal wells.

Horizontal wells require either matrix stimulation or hydraulic fracturing for removing damage caused during drilling and for penetration into the reservoir to increase contact area.

Pumping stimulation treatments into long horizontal intervals proved less effective than expected. The treatments

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**FRACTURE GEOMETRY**

$X_f = $ Fracture half length  
$\sigma_{h,\max} =$ Horizontal stress maximum  
$\sigma_{h,\min} =$ Horizontal stress minimum  
$D =$ Distance
Openhole multistage fracturing with mechanical packers was developed in 2001. Between 2001 and 2006, OHMS became the completion of choice for low-permeability horizontal wells in North America. One estimate is that to date more than 8,000 OHMS fracturing jobs have been performed worldwide. Various service companies have developed several competitive products.

Typically, multistage fracturing methods were infracted by the lowest most-to-gray zone. If the zone was not gas productive, the treatment had little or no effect on production.

Acid washing by jetting the formation also has not improved long-term production.

It became apparent that the proper way for stimulating horizontal wellbores was to treat segments in the borehole separately.

The industry has used many methods such as cementing a liner, perforating, treating, plugging the zone, and then moving up hole to stimulate subsequent intervals (plug-and-perf method). Most of these early isolation methods were either ineffective and risky or prohibitively expensive and time consuming.

**SAUDI ARABIAN OHMS INSTALLATION IN GAS RESERVOIRS**

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**RESERVOIR CONTACT ACHIEVED**

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vals with fracturing ports between packers. After a hydraulic force sets the packers, the system becomes robust and permanent.

In an OHMS system, fracturing starts from the toe of the lateral and proceeds toward the heel. A ball-drop mechanism isolates each treated zone from the untreated zones. Typically, a company will flow back and clean up the borehole after the stimulation of all stages.

Saudi Aramco based the placement of the packers and ports on openhole logs. The objective from the reservoir standpoint was to segment the horizontal wellbores into several compartments and to conduct hydraulic fracturing treatments in each compartment.

The results from the treatments made it possible to sort through and analyze the formation, reservoir, completion, and production test data and look for trends and correlations among the variables.

The well completions have included OHMS assemblies from several major companies. Overall results were good but some specific differences have been noted. The evaluations of these assemblies were based on the mechanics of the completion system, operational aspects of deployment, and results obtained after the treatment.

The following paragraphs will identify the variables and discuss the ways in which these variables can affect production results and also comment on best practices to improve success.

Table 1 summarizes the results to date from the installations placed in carbonates and sandstones in Saudi Arabia's gas fields.

### Well azimuth

From the fracturing point of view (and therefore productivity), the preference is to drill a horizontal wellbore toward the minimum stress ($\sigma_{\min}$) so that the hydraulic fracturing creates transverse (or orthogonal) fractures.\(^1\)\(^2\)

Fig. 3 depicts longitudinal and transverse fracture geometries, the difference between the two configurations, and compares them with a single fracture created from a vertical well.

In case of transverse fractures, a job can place several fractures, one beside the other, because the fractures would basically stay independent of each other.

For a longitudinal fracture, however, the created single lateral wellbore may require a higher mud weight for stability.

As seen in Table 2, the reservoir contact areas increase with the number of fractures and horizontal wells surpass vertical wells. This is the initial incentive to drill horizontal wells toward $\sigma_{\min}$ and place as many fractures as needed and desired for long-term sustained productivity. Of course, one uses a net-present-value calculation to determine the economic aspects for selecting the optimal number of hydraulic fractures.

Wells drilled in the direction of maximum in situ stress, $\sigma_{\max}$, might require lower mud density to maintain a stable wellbore. These wells are less likely to intersect open natural fractures if they exist.

The hydraulic fractures created in such well types will be longitudinal. On the other hand, if wellbores align toward $\sigma_{\min}$, the wellbore may require a higher mud weight for sta-
bility while drilling. This configuration will allow the intersection of more open natural fractures but can generate high mud loses. Hydraulic fractures created in such a wellbore will be transverse.

Although challenging, the improved long-term sustained productivity with an OHMS completion and effective multistage fracturing (MSF) treatment justifies drilling wells toward $\sigma_{\text{min}}$.

**Formation type**

The following three different types of formations in Saudi Arabia are considered for MSF treatments.

1. **Moderate and high-permeability carbonates.** Wells completed with OHMS in these reservoirs and fractured have shown good results. Initial production has been higher than wells completed traditionally, with either openhole or perforated liner systems. Post-fracture production decline has also generally been much slower.

2. **Low-permeability carbonates.** Wells completed in these reservoirs have been somewhat challenging because they require higher treating pressures to initiate and propagate fractures. Nearly all wells drilled in such formations are not have such signature.

If the first stage of the treatment shows a good fracture signature from the pressure response and the subsequent zone shows no unique pressure signature, the probability is high that the initial treatment had broken in and propagated into the next zone. This indicates that the openhole packers for isolating neighboring intervals could not contain the pressure and were bypassed.

For an unbalanced system, this can happen due to the piston effect exerted on the system during the first stage of the treatment.

**OHMS assemblies**

Saudi Arabia’s gas wells currently have three primary types of OHMS systems (Fig. 4). The differences among the assemblies are important and need to be well-understood to make the optimal selection choice and to conduct fracturing that will give desired gas rates.

One essential part within the OHMS assemblies is the openhole packer system. Of the two major types of packers used, one is a mechanical packer that is set with hydraulic pressure and the second type is a swellable packer (SEP) that along or somewhat close to the natural fracture plane, $\sigma_{\text{max}}$.

Two wells listed in Table 1 (Well No. 10 and No. 17) were drilled perpendicularly to the natural fracture plane. Well No. 10 was inconclusive because of mechanical failure of the hardware. In Well No. 17, the OHMS assembly became differentially stuck and had to be set about 300 ft higher than planned. This resulted in the fracturing ports and packers in undesired positions. Further intervention will be required on this well to mitigate the problem.

3. **Sandstone.** Three wells have been completed with OHMS assemblies in relatively tight formations. Well No. 8 was drilled along the natural fracture plane and Well No. 9, perpendicular to the natural fracture plane. Well No. 13 was drilled near-vertical, at only a 30° inclination.

Production from Wells No. 8 and No. 13 was less than expected. Well No. 9, drilled perpendicular to the natural fracture plane, produced at an excellent production rate, however.

Each of the four treatment stages on this well showed unique fracture signatures confirming independent fractures, while the previous two wells did not have such signature.

If the first stage of the treatment shows a good fracture signature from the pressure response and the subsequent zone shows no unique pressure signature, the probability is high that the initial treatment had broken in and propagated into the next zone. This indicates that the openhole packers for isolating neighboring intervals could not contain the pressure and were bypassed.

For an unbalanced system, this can happen due to the piston effect exerted on the system during the first stage of the treatment.
pumping of cooler fluids. The effect of temperature change alone can cause high tensile loads due to shrinkage of the liner.

If the OHMS assembly moves after the packers are set, the packer elements will encounter traction or elongation and damage will occur, compromising the packer sealing capability.

An anchor mechanism can resist the piston-type movement often occurring during fracturing operations. An anchor, therefore, is highly recommended.

The lowermost fracturing port can have two possible configurations. It can either be placed above or below the lowermost packer.

A balanced configuration occurs when the first-stage fracturing port is above the lowermost packer. In this case, during the pumping of fracturing treatment through this fracturing port, the hydraulic forces on the packers above and below are equal. These equal forces cancel out each other and there is no net force trying to move the OHMS assembly.

An unbalanced configuration occurs when the first-stage fracturing port is below the lowermost packer. During the pumping of the treatment through this fracturing port, hydraulic force applies only to the packer above and this will try to piston the OHMS assembly upwards. If this piston force is greater than the anchoring force, the OHMS will shift, compromising the packer seals.

Based on analysis and field results, all OHMS assemblies installed in the future in Saudi Arabia will be in a balanced configuration.

All service companies use ball-activated fracturing sleeves to open access to different stages. The different increment diameters between ball sizes are in 1⁄2 in., 1⁄4 in., and 1⁄8-in. increments.

With smaller increments, the overall ball seat size is higher, thereby providing better access and communication after the treatment when balls are flowed back. In some cases, the OHMS fracturing sleeves can only be reclosed after milling out the ball seats.

The option of reclosing fracturing sleeves with the balls seats in place is a better and preferred option. This avoids the risk of needing an intervention.

**Pressure rating**

So far all OHMS assemblies run in Saudi Aramco’s deep gas wells have had a maximum 10,000-psi pressure rating. For carbonate reservoirs, this rating has been sufficient because the maximum breakdown and stimulation pressures reached were 8,500 psi, which is within the comfort zone.
for this equipment.

Some lower permeability carbonates required pressures near 10,000 psi to break down the zone.

As for sandstone reservoirs, few wells have OHMS completions. One well completed in sandstone did test at a high gas rate.

The sandstone completions require fracturing with proppant. Although the stimulation and treatment pressures observed on these initial wells were within the 10,000-psi ratings for this equipment, the expectation is that tighter formations will require higher bottomhole pressures (BHPs).

With proppant fracturing, screening-out while pumping high-viscosity fracturing fluids at a very high rate and pressures is a risk. If a premature screenout occurs, the BHP can exceed maximum equipment rating due to sudden loss of friction pressure while surface and hydrostatic pressures are at their maximum.

Saudi Aramco currently is exploring the use of 15,000 psi equipment to get the pressures required for breakdown and stimulation without being limited by maximum pressure.

**Hydraulic fracturing port**

Pressuring the OHMS assembly hydraulically opens the first port. It is very important that this port opens smoothly and trouble-free.

Typically, a well after being completed with an OHMS assembly remains shut in for a period before the fracture treatment. Depending on the situation and schedule, completion fluids may damage the fracture ports if the well is shut in for a long time.

The ports must be tested to withstand the completion fluids, temperature, and bottomhole environment. A high quality control process will ensure a smooth actuation and positive functioning of the port.

Preferred is a dual-sleeve hydraulic fracturing device because the opening of this device is essential to the operation. So far there have been no occasions where a dual-sleeve hydraulic fracturing device has failed to open.

By analyzing the pressure decline after pumping (Fig. 5), one can determine if a port has opened or not. The pressure response (decline) must be separated from the decline that occurs as the system is bled off.

Fig. 5a shows that the wellbore pressure is maintained as injection proceeds. Even when the injection rate drops to zero (the last stage starting at ~380 min), the pressure (red color line) remains the same. This clearly shows that the fracture port has not been opened.

This is different from Fig. 5b where at a 3 bbl/min injection rate (blue curve) at about 3.5 min into pumping, the pressure suddenly drops indicating that the port has opened.

**Openhole size**

In Saudi Arabia’s deep gas wells, OHMS assemblies have been deployed in two different hole and completion sizes:

5¾-in. openhole with a 4½-in. liner and 8¾-in. openhole with a 5¾-in. liner.

The wells with assemblies in the 8¾-in. openhole generally produced better, probably because the wellbores have a greater contact area with the reservoir or a better reservoir quality. Currently not enough information is available for a firm conclusion.

For horizontal wells with OHMS completions and multistage treatments, the size of the openhole should not be a factor. Openhole contact area is negligible compared to the fracture area.

**Stage size**

Depending upon reservoir properties, contact length, and well configuration, an increased number of stages will add to production as mentioned previously (Table 2). The economics, however, need to be calculated because every additional stage has an incremental cost.

Fig. 6 shows the inflow performance relationship (IPR) curve for an example case with a 2,000-ft horizontal lateral wellbore in a 10 md-ft interval. For a flowing wellhead pressure of 1,500 psi, the plot clearly shows the benefits of additional fractures.

The plot shows a 50-60% improved productivity if the number of induced fractures (NFRs) increase from 1 to 8.

The number of stages in Saudi Aramco’s gas wells has
ranged from 2 to 4 because most of the wells align with \( \sigma_{\text{max}} \), thereby restricting the number of independent fractures that a treatment can realistically induce.

Wellbores separated into an increased number of shorter intervals have had greater production rates. In general, this indicates that the increased number of shorter intervals and more concentrated stages will increase the contact area across the entire openhole section.

Stage lengths have varied from 200 to 1,000 ft. One installation (not yet stimulated) had packers placed immediately below and above the production intervals as determined from openhole logs. Nonproductive sections, as indicated by the openhole logs were blanked off, thus preventing stimulating nonreservoir intervals. Another purpose for these additional packers is to create space between fracture stages in case the treatment propagates longitudinal fractures.

**Flow back between stages**

Typical MSF operations worldwide focus on the efficiency of the pumping, so that the treatment stimulates all stages sequentially before commingling all zones during the flow back.

This is how the first MSF operations were completed in Saudi Arabia. In all operations with successfully deployed operations, the treatments led to good production performance. It was decided, however, to flow back each stage immediately following the fracturing treatment with the goal of evaluating the performance of individual segments.

In this case, the fractured lower stages remain open during the fracturing of the upper stages. The flow back is then a cumulative commingled stream.

For example, if the post first-stage production was 5 MMscfd and the combined flow back of the first and second stage was 12 MMscfd, then the assumption was that the second stage contributed 7 MMscfd.

This idea works well in theory but in practice the results were not always conclusive. Stage 1 flow back from Well No. 6 was very good and the measured rate was 15 MMscfd. Following the opening of the Stage 2 port, the injection pressure was much lower than expected. It was concluded that the fluid being pumped into Stage 2 was most likely re-entering the initial fracture created from Stage 1. This led to the on site decision to discontinue the fracturing for Stage 2 and instead pump a matrix acid treatment using diverters into the newly opened stage.

After flow back of Stage 2, some incremental production was observed, about 18 MMscfd total combined flow rate; and therefore, Stage 2 contributed an estimated 3 MMscfd, much lower than expected from this zone.

After analysis of the post-job data, the consensus opinion was that during flow back of the initial stage, the reservoir went from a highly positive charged zone in which the large
The reservoir is tight and highly heterogeneous. The initial calculated permeability-thickness product (kh) for the well was about 10 md-ft, which falls within the tight sand category.

Based on the openhole log, the treatment design involved four-stage fracturing and deployment of an OHMS with fracturing ports placed next to the somewhat better developed porosity sections (Fig. 7). The treatment went well, pumping about 650,000 lb of proppant in four stages. After cleanup, the well produced at an initial 18 MMscfd rate with a 2,000 psi flowing wellhead pressure. The posttreatment deliverability test indicated a 10 md-ft kh, about a 700-ft combined fracture length, and a 700 md-ft fracture conductivity, indicating a successfully designed and implemented fracture treatment (Fig. 8).

Fig. 9 shows the heterogeneity of the Khuff carbonate reservoir. Within a small distance, well properties can be highly variable as seen from the production response from the four wells in Fig. 9. Because of this, the formation requires the drilling of horizontal laterals for intersecting more reservoir area as well as MSF treatments to improve contact further and tap the full potential of a well.

Most of the tight Khuff reservoirs now have horizontal lateral completions and include OHMS assemblies and multiple induced fractures for improving recovery.

Fig. 10 is an example of multistage completion in carbonates that has three fracturing ports in the developed reservoir.

amounts of fluid pumped had pressurized the formation, to becoming a negatively charged zone after the flow back when the zone became drawn down and underpressured. As a consequence, the in situ stresses decreased in this interval.

When the Stage 2 port was opened, therefore, the fluid followed the path of least resistance and in this case the majority of the treatment was pumped into the lesser charged initial fracture (Stage 1). The fiber diversion system used in the matrix treatment for Stage 2 helped to divert some of this flow away from the Stage 1 fracture; however, it would not initiate new fractured sections, and therefore the well did not attain the production target.

**Reservoir quality**

Two main treatment types currently conducted in tight gas reservoirs are proppant fracturing in sandstones and acid fracturing carbonates.

Because of the high vertical heterogeneous nature of the formation and relatively low permeability, the development plan included the drilling of horizontal wells and conducting an MSF operation. An example well (SD-1) drilled in the direction $\sigma_{\text{min}}$ illustrates this operation (Fig. 8). The well azimuth was optimal because the vertical fractures generated will be transverse.

The well encountered about 1,400 ft of net pay thickness with moderate porosity. The openhole log confirms that the
Treatments pumped
Typical acid fracturing in Saudi Arabian carbonate formations involves pumping the treatment in several phases.

The initial treatment begins with a pad stage to extend the hydraulic fracture length and then pumping 28% hydrochloric acid to etch the fracture surface, create wormholes, and hold the fracture open.

In the cases previously discussed in which communications was observed between stages, the subsequent stage was designed as a matrix acid treatment.

This new design, to avoid pumping much fluid in the previous interval, used diversion fluid to increase the chance of treating the new interval.

When the fiber-laden viscoelastic system acid reaches the formation, it viscosifies and temporarily restricts the flow into the treated interval, diverting the acid into the new section. One can typically omit polymer-based pad and buffer stages in this remedial treatment design.

The CR-1 sidetrack is an example well with 1,600 ft of net pay (Fig. 11). The treatment included the installation of the OHMS assembly for treating the entire interval in three stages.

The well was cleaned up after stimulating each stage to estimate the potential production from each stimulated interval. Fig. 12 and Table 3 present the production from Stage 1 (acid fractured), Stage 1 and Stage 2 combined (Stage 2 matrix acid), and all stages combined (Stage 3 matrix acid).

The well has a 20 MMscfd stabilized flow as shown in long-term production profile (Fig. 12d), indicating a very successful MSF treatment.

In proppant fracturing treatments for sandstone formations to reduce the probability of screening-out, the initial approach was fairly conservative in terms of proppant size, loading, and total proppant mass.

The job involved the pumping of a tapered design with finer 30/50 mesh proppant in the initial stages followed by coarser 20/40 mesh proppant as a tail-in to help add fracture width and conductivity in the near wellbore area.

Acknowledgments
The authors thank the management of Saudi Aramco, Schlumberger, and Packers Plus Energy Services for permission to publish this article.

STAGE PERFORMANCE

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The authors
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