Efficient Technology Application to Optimize Deep Gas Well Completions in the Khuff and Jauf Formations Requiring Hydraulic Fracturing in Saudi Arabia

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Abstract

The first phase of an accelerated project to develop Saudi Arabia’s deep gas potential has been sanctioned, and a large number of new gas producers are currently being drilled and completed. A number of wells have been either acid or hydraulically frac’d, and preliminary production tests have shown significant productivity increases resulting from this type of stimulation. Consequently, plans have been finalized to frac most existing and future wells in this development.

Fracture initiation pressures average 16,000 psi. at downhole conditions, and H₂S has been found present in several of the formations, so well completions capable of withstanding such conditions are of critical importance. This paper describes how the acquisition of WellCat™, Landmark’s tubing stress analysis software program, and rigorous scrutiny of well completion components helped Saudi Aramco identify a significant number of mechanical weak links previously overlooked by an in-house computer program. The ability to analyze well completions in intricate detail, and model each frac stage with realistic fluid rheology, provided a powerful tool which helped identify weak links in need of removal to prevent potential problems.

A systematic approach to evaluate existing and planned well completions was implemented, close cooperation between several Saudi Aramco groups and Landmark established, specific modification recommendations issued, and an action plan to improve future completions and strengthen existing ones was put in motion.

Introduction

Saudi Aramco first developed non-associated gas from the Khuff formation in the Shedgum and Uthmaniyah areas of the Ghawar field in the early 1980’s, to provide fuel and feedstock to in-Kingdom industry during periodic shortfalls in associated gas supplies. The ever-increasing energy demand in the Kingdom has turned non-associated gas into an important source of energy. Non-associated gas well potential comes from the Khuff and pre-Khuff reservoirs. A large-scale development program to meet projected high demand and to replace crude burning in some regions of the Kingdom is underway. By 2002, projected non-associated gas demand will be in excess of 3 BSCFD, while current tested well potential is below that rate. A number of programs have been initiated to ensure supply targets are met. These include: exploratory and development drilling, production optimization from existing deep gas wells, debottlenecking of existing gas processing facilities, and design and construction of new facilities. Additional development phases have been sanctioned and implementation will occur throughout coming years.

The Khuff formation is a carbonate evaporate. Gas composition varies widely throughout the Ghawar field. The hydrogen sulfide content ranges from 0 to 9-mole %, carbon dioxide from 0.5 to 4-mole %, and nitrogen from 7 to 14-mole %. Average reservoir datum depth is 11,000 ft SS, average initial reservoir pressure 7,500 psig, and average temperature 275 °F.

The Jauf formation is a thick sandstone with the presence of fibrous illite clays, which can contribute to formation damage and formation sand production. It produces sweet gas with high condensate content. Average reservoir datum depth is 13,000 ft SS, average reservoir pressure 8,500 psig and average temperature 300°F.

The traditional stimulation methods used in existing non-associated deep gas wells were, until recently, matrix stimulation and perforation acid washing aimed at removing near-wellbore damage. However, the new development areas have shown reduced reservoir quality, which usually renders traditional stimulation methods ineffective. Furthermore, early
testing of a small number of Jauf wells has shown that sand control may be required.

A number of acid fracs in Khuff wells and hydraulic propped fracs in Jauf wells have been successfully implemented, thus proving fracturing to be a viable productivity enhancement technique in this development. The significant successes achieved early in the program supported the decision to move forward with a large-scale fracturing campaign covering most of the wells in the development. However, collected field data and experience have shown that hydraulic fracturing will be a challenging and complex task. Measured fracture initiation gradients in the Khuff range from 1.0 to 1.4 psi/ft. Required average treatment pressures for effective fracture growth average 16,000 psi. at reservoir depth, wellhead tubing injection pressures range from 10,000 to 12,000 psi., annular pressures up to 7,000 psi. are needed for tubing support, and treatments are pumped at injection rates up to 80 bpm.

Well completions capable of withstanding such harsh conditions are an essential component of the development program. Deep gas well completions in the Ghawar field to date are of two basic types: a) liner top PBR; b) packer top PBR. Both completion types incorporate a seal assembly with allowable upward movement. The majority of wells in the new development phase have been completed with 4-1/2", 5-1/2", or tapered 15.1# and 13.5# C-95 grade tubing with New Vam connectors. Several L-80 material components were also incorporated in the tubing string. All wells are completed with 7" or 7" x 4-1/2" cemented liners. Cross-sections of typical completions are shown in Fig.1.

Higher than predicted minimum stresses found while drilling new wells, adoption of a different stimulation philosophy based on the positive results obtained from hydraulic fracturing, and evaluation of requested detailed connector performance data, signaled for Saudi Aramco engineers the need to review the applicability of past assumptions and completion practices to the present environment. Corporate commitment to ensure completion integrity for new predicted stimulation and producing conditions in deep gas wells, led to the implementation of a systematic approach to re-evaluate existing and planned completions. The re-evaluation task was completed in a timely manner. Recommendations with detailed and specific modification requirements for individual wells were issued, and a timely completed workover campaign achieved stringent completion integrity requirements in wells with identified weak links.

**Historical Perspective of Tubing Stress Analysis in Deep Gas Development Project**

Tubing stress analysis was not considered necessary for oil producing wells completed in the Ghawar area early in the development, because most wells were completed with 2-7/8 or 2-3/8 kill strings and produced up the casing. Non-associated deep gas development started after oil development in the area had been going on for a number of years, so most of the completion engineers who were involved with the oil development project transferred to the new deep gas development program, and brought with them the completion practices and expertise accumulated through years in the area.

Based on similar practices for gas wells in other fields around the world, Saudi Aramco engineers designed completions with floating seals inside a PBR. The tubing was landed with enough pick up above the PBR so that the seals would float while keeping the locator sub above the PBR. Packer completions with floating seals were also introduced a short while later. Total maximum upward movement due to temperature change for predicted stimulation, production and killing loads was estimated at 12 feet. Tubing movement due to piston effect was generally disregarded because it was wrongly assumed, from lack of industry consensus at the time that provided the seal and tubing diameters were similar, the piston effect forces would be negligible. Thus, based on the maximum expected tubing movement, plans were made and orders placed to complete all new wells with 24 ft. long PBRs. In addition, packers rated to only 10K psi. were purchased under the premise that higher rated equipment was not necessary, because with floating seals no tubing to packer forces are present. Furthermore, the general view at the time was that wells would only require matrix acid stimulation to achieve gas rate targets.

After Hammerlindl published a paper in 1977, which provided clarity to some of the issues the industry had struggled with, Saudi Aramco’s engineers performed more detailed analysis and concluded that their original estimate of maximum tubing movement was optimistic. Movement due to piston effect could not be disregarded. Spacing out the tubing with the
estimated needed pick up would keep the locator sub from touching the PBR under tensile pressure loads, but would make the floating seals pull out of a 24 ft. long PBR under compressive pressure loads. At this stage, it became necessary to re-think the original completion philosophy and use a new approach, but it had to be done with the added constraint that all the new downhole equipment had already been delivered and could not be exchanged. The new approach was to calculate the maximum tubing length change under compressive pressure loads, and then space out the tubing in such a way that the floating seals would remain inside the PBR.

The need to have the ability to perform more detailed tubing stress analysis became evident. Discussions over appropriate evaluation criteria ensued and consensus was reached on two main issues. It was agreed that forces acting on tapered strings and tubing to locator sub crossovers could be ignored, because it was generally assumed that bending stress would be small due to their short length. It was also agreed to assume that the seals would eventually stick in the sealbore when the locator sub bottomed out on top of the PBR or the packer. This was obviously an oversimplification because the seals could in fact stick in any position. Forces acting on the completion section below the locator sub were also ignored, because compressive loads are not significant at flowing conditions. However, their significance under stimulation conditions was overlooked. With no production data available prior to completing the first wells, it was necessary to make assumptions about temperatures and pressures at predicted stimulation, production and shut-in conditions.

A mainframe computer program was written in the early 1980’s by a senior Saudi Aramco completions engineer to fulfill the need for faster and more detailed tubing stress analysis. The program was used until mid 1999. Based on the discussed assumptions and criteria, all wells were found to meet completion integrity requirements for predicted load cases. However, significant program limitations were identified upon determination that fracturing would be necessary to achieve gas rate targets, which have since rendered the computer program obsolete. The main program limitations were its inability to effectively estimate tubing bending stresses, and to assess connector strength under compressive loads. The latter became a significant issue for deep gas completions when, in recent times, tubing-casing annulus communication problems developed with regular frequency in old and new wells alike. Loss of a gas tight seal in the connector was identified as a likely cause of the problem. Extensive consultations with the manufacturer of the New Vam connectors used in most wells followed, and confirmation was obtained that the sealability of the connectors was not tested in high compressive pressure load conditions and are, thus, rated only to 40% of pipe axial strength in compression. This was not accounted for during initial completion design.

The combination of these issues motivated Saudi Aramco to search for alternative computer programs with the ability to perform rigorous tubing stress analysis for a wide variety of load conditions. Simultaneously, a new testing protocol with the specific purpose of qualifying field proven connection designs to higher compression ratings under combined loading situations was completed. Following a systematic evaluation of different software packages, the decision to buy WellCat™ was made.

**New Tubing Stress Analysis Approach**

With the newly acquired ability to perform detailed and thorough tubing stress analysis, Saudi Aramco management and technical staff recognized the need to re-analyze all wells that had previously been found to meet completion integrity requirements. A small team comprised of Drilling and Production engineers and a Landmark technical consultant was formed. The team was given the task of identifying weak links, if any, and issuing specific recommendations for implementing completion modifications in existing and future wells where necessary. The work had to be completed under a tight deadline, because full mobilization for a fracturing campaign had already started and new wells were being drilled and completed at a fast pace.

A systematic approach and methodology to ensure rigorous analysis was devised and the following actions implemented by the team.

1. All drilling and completion records were meticulously reviewed to verify actual completion components and wellbore conditions during tubing space out operations. Field personnel on location during completion operations were contacted when reporting discrepancies emerged, and asked to provide their account of events so that actual vs. reported events could be reconciled.

2. Vendors, service companies and contractors were contacted and asked to provide detailed specifications for supplied completion components. Thus, data were requested for component type, grade, weight, length, inside and outside diameter, pipe and connector burst, collapse and axial load ratings, temperature rating, packer tubing-to-packer load rating, thread type and rating, and other vendor specific pertinent information.

3. Met with the New Vam connector manufacturers to obtain connector performance details for different load scenarios and conditions. Established sequence of load conditions, which would cause a connector to lose tight gas seal, and generated Von-Mises (VME) envelopes to identify key operating constraints.

4. Met with Reservoir engineers and technical staff involved with hydraulic fracturing stimulation design to discuss implementation procedures, treatment objectives,
expected maximum injection pressures, treatment volumes, number of stages, flowback procedures, etc. Evaluated designs and results of all previous stimulation treatments pumped in existing deep gas wells to identify common trends and ranges. Obtained stimulation designs for wells already scheduled for treatment, and used historical treatment data to develop load cases for every frac stage.

5. Analyzed production history and fluid PVT properties from existing deep gas wells, and built a hydrocarbon composition database including the fluid variety present in the Ghawar field.

6. Requested from service companies operating in Saudi Arabia detailed rheology data for the fluids in each treatment stage, at expected temperature and injection rate conditions during a treatment. Comparison runs of predicted vs. actual pressure data collected during previous treatments were made for calibration purposes, and results showed very close pressure and temperature matches.

7. Each completion was split in as many components as necessary, for modeling purposes, so that axial loads and stress effects could be clearly observed and weak links identified. Thus, the tubing was split in several sections according to weight, material and connector type. Components such as, nipples, flow couplings, crossovers, locator subs, spacer bars, seal units, pup joints, etc. were also individually defined in the program. An example of how a typical completion was defined and modeled is depicted in Fig. 2.

8. Reached consensus on WellCat™ modeling criteria and load cases to evaluate. Agreement was obtained on safety factors, ratings for New Vam and other connector types, buckling constraints, axial load transmittal in different completion components, forecasted gas production, condensate and water rate ranges, maximum operating pressure drawdown, maximum treatment injection and annular pressures, flowing and shut-in wellhead pressure and temperature ranges, and annular pressure at flowing and shut-in conditions.

9. Agreed on packer depth criteria for different completion types and load cases. For packerless completions, packer depth was assumed at the bottom of the seal assembly for both stimulation and production load cases. This was based on how tensional and compressive forces are transmitted throughout the completion. For packer top PBR completions, the packer depth was assumed at the top of the packer for stimulation load cases, and at the bottom of the locator sub for production load cases. The same packer depth for stimulation and production loads was assumed for liner top completions. Details are shown in Fig. 3.

Fig. 3 – Packer Depth Selection Criteria for Modeling Purposes

10. Included buckling constraints into the modeling to try to accurately emulate actual tubing movement conditions, particularly under compressive pressure loads. When exposed to compressive pressure loads, a section of the sealbore assembly pulls out of the PBR but another section remains inside. Under this scenario, the section outside the PBR is exposed to significant bending stresses, whereas the section inside is not, because there is only a small cross-sectional area change. The length of the exposed section varies as a function of axial load so worst-case scenario conditions, when maximum movement occurs, were assumed for modeling purposes. Maximum movement length was subtracted from the sealbore assembly length, and a buckling constraint applied to the length differential. The buckling restriction ID, required as an entry in WellCat™, was calculated as

\[ ID_b = (ID_r \cdot OD_i) + OD_r \]
A buckling constraint was also applied to the locator sub, because being a sturdy, large OD, short component; it is not expected to be significantly affected by bending stresses.

11. Selected following design factors: a) 1.1 for pipe burst; b) 1.0 for pipe collapse; c) 1.3 for pipe axial load; d) 1.25 for pipe triaxial stress; e) 1.0 for connector triaxial stress; f) 1.1 for connector burst; g) 1.3 for connector tension. Connector compression de-rating was entered as a maximum axial load value in the WellCat™ proprietary connections spreadsheet.

12. Completed Saudi Aramco testing protocol to qualify several connection designs to higher compression ratings.

**Discussion of Analysis and Results**

The previously described implemented actions symbolized the "ground rules" for rigorous tubing stress analysis, and reduced the potential for obtaining different interpretations of WellCat™ modeling results. These ground rules simplified the process of evaluating modeling results and issuing recommended actions for individual wells. Wells that deviated from agreed modeling criteria were determined to lack the required completion integrity to withstand predicted load conditions.

Load cases modeled fell into the following categories: 1) hydraulic acid fracturing loads, 2) hydraulic proppant fracturing loads, 3) matrix acid treatment loads, 4) short term production loads, 5) long term production loads, 6) cold shut-in loads, 7) hot shut-in loads, 8) pressure testing loads. Each stage for typical stimulation treatments was modeled as a separate case with fluid volumes, rheology, proppant concentration, and injection rates equivalent to those expected to be pumped in each of the wells evaluated. Matrix acid loads evaluated were similar to treatment designs previously pumped in wells with similar characteristics to those being evaluated. Screen-out load cases for propped hydraulic fracture treatments were also modeled. Production, shut-in and pressure testing loads were based on Saudi Aramco's operating philosophy, requirements and constraints.

A total of 21 completed wells were modeled and scrutinized in detail by all team members. Results obtained identified a consistent number of weak links in most wells, which rendered their completions unable to meet required completion integrity. Identified weak links were: New Vam connectors, locator subs, spacer bars, crossovers, and seal units. Most of these were L-80 material components. Predicted failure mode in the overwhelming majority of cases, as depicted in the example shown in Fig. 4, was loss of connector gas tight seal in loads exceeding connector compression rating under compressive pressure loads. This condition is likely to cause tubing-casing annular communication problems once exposed to a sequence of tensile and compressive pressure loads.

Fig. 4 – Example of Predicted Failure Mode Caused by Loss of Connector Gas Tight Seal

Pumping a treatment at the high pressure and rate conditions required to initiate a fracture, would have exposed identified weak links to axial loads in excess of the triaxial limit in several of the scrutinized wells. An illustration of the predicted failure mode in one of the evaluated completions is shown in Fig. 5.

Fig. 5 – Example of Predicted Failure Mode Caused by Axial Loads Exceeding Triaxial Limit
High axial loads generated by bending forces acting on short lengths were common in most evaluated completions. This became a relevant factor, because some of the historical completion design decisions made were based on the assumption that bending stresses were low in short completion components. A good example of instantaneous doglegs caused by bending can be seen in the evaluated completion shown in Fig. 6.

Actions Taken
Recommendations to work over 15 of the 21 evaluated wells were issued by the team. The remaining wells were classified as "borderline", because their completion either failed to meet completion integrity criteria only for screen-out loads during a proppant frac, or connector axial load rating was exceeded only slightly. Detailed required changes were specified for each well and, where possible, several options were provided. Most of the recommended changes required replacement of existing connectors with higher compressive load rating connectors, and/or installation of new completion components manufactured with higher axial compressive load rating material.

Saudi Aramco management took prompt action, and a work over campaign was sanctioned. A quick turnaround was required in order to meet a tight schedule for delivery of gas rate targets. Team recommendations called for replacing all L-80 material components with C-95 and higher, but it soon became apparent that manufacturing time would take several months, and other recommended changes would not be possible. Additional extensive WellCat™ modeling was conducted in search of alternative options that could be quickly implemented while ensuring that completion integrity requirements were met. Results showed that a few simple completion modifications would go a long way in meeting such requirements, and they were quickly implemented. Some of the modifications made were:

1. Locally manufactured new locator subs with P-110 material and with connectors rated at axial loads of 100% pipe body yield strength, and installed in the majority of worked over wells.

2. Locally manufactured new spacer bars with C-95 material and 100% rated connectors, and installed in most of the worked over wells.

3. Added a short section of P-110 pipe below the spacer bar in those completions where the seal assembly could not be replaced, nor connectors re-threaded. The objective was to ensure the spacer bar had higher rated connectors at both ends, thus turning the short section of pipe below it into the weak link. However, tubing movement calculations showed that this short pipe section should remain inside the PBR when under compressive pressure loads, and the combination of being exposed to low bending forces and having a high load rating ensured that all completion integrity requirements were met. Furthermore, it no longer became necessary to modify the seal unit, another of the component identified as a weak link in most wells, thanks to the changes described herein.

WellCat™ runs showing the effect of loads in one of the weak completion components before and after implemented changes are depicted in Fig. 9 and Fig. 10.
4. Thousands of feet of pipe were re-threaded with 100% rated connectors at Saudi Aramco’s machine shop and set in worked over wells.

Conclusions

1. WellCat™ proved to be a flexible and effective tool for identifying mechanical weak links, previously overlooked by an in-house computer program. Ability to perform multiple sensitivities, and quickly evaluate “what if” scenarios was instrumental in providing solutions to a complex problem.

2. Management support and commitment to delivering quality well completions for long-term operational success superseded cost concerns, and ensured timely and efficient implementation of this project.

3. Systematic tubing stress analysis approach developed for this project is now required for designing all new deep gas well completions in Saudi Aramco.

4. All 15 worked over wells have been frac’d and are trouble-free. Furthermore, no new wells completed with recommended optimization changes have experienced completion integrity problems. Three of the six “borderline” wells that were not worked over have since developed tubing-casing annular communication.

5. Several major initiatives are underway at Saudi Aramco to further optimize completion and operating practices in deep gas wells.

Nomenclature

\[ ID_b = \text{buckling restriction inside diameter, in.} \]
\[ ID_i = \text{inside diameter of component housing smaller restricted component, in} \]
\[ ODL = \text{largest outside diameter of restricted completion component, in} \]
\[ ODc = \text{nominal outside diameter of completion component, in} \]

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References