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Reservoir Optimized Fracturing - Higher Productivity From Low- Permeability Reservoirs Through Customized Multistage Fracturing

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Abstract

Economic exploitation of low-permeability or tight sandstone and carbonates can be an elusive endeavor. New technologies and approaches are needed to make these more challenging reservoirs economically attractive. The completion technique discussed in this paper has been successfully employed in previously non-economic gas reservoirs in North America. The main focus of this completion technique is enhanced reservoir connectivity with the wellbore. Other completion techniques have previously been used to successfully improve reservoir contact and enhance production. These techniques are similar in their focus on improved reservoir connectivity by compartmentalizing the wellbore into multiple sections. They do, however, have their limitations in low-permeability or tight formations.

The novel completion technique presented in this paper involves horizontal drilling through a reservoir combined with compartmentalizing the wellbore into multiple sections. Each wellbore section is then individually fractured in order to effectively propagate fractures through the reservoir, thus greatly increasing productivity in each zone. Up to twenty-four zones can be set up, allowing operators to customize their stimulation program in long-reach horizontals in heterogeneous and low-permeability reservoirs. Detailed knowledge of the existing natural fracture network, the current-day stress field, and geomechanical considerations are key inputs to a valid reservoir model, reducing the risk of establishing undesired flow paths with the aquifer, for example.

This paper will illustrate how this new technology has enabled operators to benefit from significant economic improvements through operational efficiencies achieved during the drilling and completion phase based on reduced rig time and faster, more cost-efficient completions. Water shutoff options available with this new type of approach will also be discussed. Multistage fracturing leads to higher initial production, improved reservoir drainage, better control on fracture propagation, and controlled production from fractures in low-permeability sandstone and carbonate reservoirs as well as in gas-shales, which will be illustrated with case histories from these operating environments

Introduction

The Middle East has profited from high quality oil and gas reservoirs for many decades. Over the last couple of years operators have started assessing the economic potential of “tight” or low permeability reservoirs as well as unconventional reservoirs, such as shale gas. Similar reservoirs have been developed successfully in other countries, ranging from the tight gas sandstones in Oman, Europe and North America all the way to the gas-shales in the US. Learnings from these plays need to be reviewed to determine their applicability to the reservoirs in the entire Middle East region since production from such reservoirs offers tremendous scope in meeting the energy needs of the Arabian Gulf, Europe, North America, India & China. The obvious obstacle in producing from tight and shale gas reservoirs is their low permeability, which requires some form of flow stimulation. In carbonates, stimulation of these reservoirs with acid through coiled-tubing is a challenge especially in long-horizontal wells as there is no effective means of deploying the acid across the entire length of the well. Further, the permeability-contrast across different sections leads to uneven stimulation of the lateral. A field proven alternative to this problem is multistage fracturing completion system.

Several papers have been written in the recent past about the tools and techniques related to multistage fracturing. Extensive case-histories have been presented to the effectiveness of this tool in North America, China and the Middle-East. However, all of these focus primarily on the execution side of the reservoir stimulation. The aim of this paper is to present a new integrated approach to Multistage fracturing. This approach integrates a series of studies such as geomechanics, wellbore imaging, horizontal drilling, completion design, fracture design and reservoir stimulation. Studies are carried out prior to drilling the well as well as after the stimulation treatment in order to better understand the reservoir, evaluate uncertainties and minimize risk, maximizing drilling and completion success. A key aspect in this approach is the post-job analysis in order to calibrate, verify, and update the models generated so as to further improve stimulation not only on the next well planned but also in real-time on the current well. To this effect, a novel workflow is presented where a multi-disciplinary team of specialists contribute to the successful design and implementation of a multistage fracturing project.

Integration, Project Management and Continuous Improvement Focus

Large scale projects, such as the development of unconventional reservoirs, require that all disciplines work together closely during the planning and execution phase. In order to facilitate this teamwork, dedicated project management resources are absolutely critical – first establishing project goals, milestones and workflows, which take into account all aspects of the HS&E, technical, commercial and legislative framework as well as guidelines from all stakeholders and then executing the project.

Project Management

Project Management is a critical competency in achieving success for large scale multi-disciplinary projects. A Project Manager is not necessarily an expert in each and every stage of the workflow but has enough knowledge to understand how the information and stakeholders interact at different stages of the project. Multinational service providers are recognizing the importance of this skill-set, encompassing management, operational and engineering expertise in a team leader, capable of determining and communicating the key performance indices at different levels and areas, incorporating stakeholders interests and focus.

The Importance of a Structured Workflow

Project management will only be effective if it can rely on a well-understood and well-documented workflow. As more and more unconventional resources are targeted, we need to realize that the key to unlocking them may require an unconventional approach and workflow – continuous learning and innovation is of paramount importance. However, agreement on the system and the workflow must exist prior to project commencement in order to ensure efficiencies and reduce risk. This becomes more complex when a large number of stakeholders or a very rigid legislative framework exists. Nevertheless, any workflow should be based on the continual improvement cycle which consists of the following key elements: planning, execution, an After Action Review to derive learnings and Best Practices, and the feedback loop, in which improvement and optimization elements are implemented in the planning phase to improve the execution phase to deliver safer, more reliable operations.

In some systems there will be clear milestones confirming that the stage-gate criteria are met before stage progression. Within each stage there should be metrics that will ensure quality deliverables at each stage. As we acquire and evaluate data to assess stage gate readiness we must always take into account the errors intrinsic to the data acquired and account for this uncertainty in the overall risk management of the project.

The workflow must have a clear beginning and end when the project in completely handed over. Therefore the question must be clearly answered when is the project over? When has it met its objectives? For this study, our closure stage is at the point when the wells are producing as per design after well testing has been confirmed as satisfactory.

Workflow Elements

As indicated above, modern workflows all consist of several steps: planning, execution, an After Action Review to derive learnings and Best Practices, and the feedback loop, in which improvement and optimization elements are implemented in the planning phase to improve the execution phase. We will now examine these elements individually to highlight the associated challenges and opportunities.

Pre-job planning

This is in many cases the most important step in any project - and also the step that is underestimated with respect to the resources and time it requires. In fact, it is safe to say that a lot of expensive and painful learnings and Best Practices are the result of poor planning. Pre-job planning is often inadequate because the complexity of projects is under-estimated, resulting in relevant personnel not being included early in the project. Project pre-planning must always be done with the “end in mind”, i.e., the end user’s project objectives and deliverables should be paramount in the planning phase. The Project Management process has been subverted when the team instructed to deliver the project has reservations on the effectiveness of the pre-planning process.

For unconventional field developments, multi-disciplinary front end research and engineering must be completed to properly done to understand the reservoir – its structure, depositional environment, geomechanics aspects and recovery factors are all vital to properly plan wellbore placement, completion type and productivity rates to ensure optimum exploitation of the reservoir.

During this, the core objective of safety and risk reduction must be established. This risk assessment has many facets: understanding the possibilities of aquifer damage, top soil and surface issues, personnel capabilities, pressure rating for wellhead equipment considering fracture treatment pressures, metallurgy considering the chemical composition of the produced gas and potential corrosion etc. These considerations have major implication on the initial CAPEX for the project, and maintenance costs that must be fully accounted for in the Project Budget.

Execution and real-time monitoring

The more concise and all-inclusive the pre-job planning, the better the execution phase. It is, however, essential that all parties initiate this phase with renewed focus as they move into field operations, arguably the most challenging part of any project. Risk Mitigations plans must be tested and implemented, as at this stage risk exposure is greatest.

Post job analysis (Learnings and Best Practices, continued optimization)

Conventionally known as a Post Job Analysis or After Action Review, this phase is just another stage of the Project Management Continual Improvement Process, the learnings generated from the operation should be well documented and regularly reviewed. Answering the following questions will drive the process:

- What did we want to do?
- What did we do?
- What went well?
- What went badly?
- Were the objectives achieved?
- What are the lessons learned
- What can be improved for the next job?

In a complex project, there may be various “feedback loops”, some of them nested within one another, as illustrated in Figure 1.

Update and improved planning for next job

On a field development level, the learnings captured by the operator can use used in any other operation, and can actually be financially quantifiable to impact an operators bottom line. The ability to Knowledge Management at every stage of the Project is very important. At the operations stage, opportunities to inculcate the key learnings should be done as soon as is possible.

Reservoir Model

The nature of unconventional gas reservoirs is complex and production performance is characterized by rapid decline after the first few years. To offset the revenue decline associated with declining production, aggressively drilling new wells has become the common practice, often at the cost of not fully integrating the available data in systematic studies to understand the underlying mechanisms for the rapid production decline. Predicting the mechanical behavior of the rock (in the immediate vicinity of a planned bore as well as further away in the reservoir proper) during drilling, stimulation, and production is not only challenging because of the vanishingly small intrinsic (matrix) permeabilities but also because of the variability of their depositional environment, age, mineralogy, maturity, temperature and pressure, depth of burial, fracture characteristics, and in situ state of stress. Hence, drilling, completing, and predicting production performance of these reservoirs successfully (i.e., largely for accurate economic evaluation) will depend upon how well we understand the reservoir and, therefore, integrated geosciences studies followed by a fit for purpose designed monitoring program (microseismic) are required in order to best characterize these reservoir types.

In this respect, geomechanics has become a vital part of the integrated approach, since it provides the possibility to evaluate a number of aspects such as: drilling performance and mitigate associated risk, selection process for packer placement, orientation and containment of an induced fracture and associated stimulation pressures required to initiate and propagate the fracture away from the well. Moreover, an understanding of existing and the stimulated volume of natural fractures can be gained through developing relationships between microseismic response and reservoir flow properties. With this latter information well performance can be better predicted and reservoir simulators calibrated.

The foundation for all the aspects listed above is a so-called geomechanical earth model (GEM), which consists of detailed rock property, pressure, and stress profiling of the overburden and reservoir. These stresses include the vertical stress (S_V), the minimum horizontal stress (S_{hmin}), the maximum horizontal stress (S_{Hmax}) and pore pressure (P_P). Furthermore, constraining the GEM spatially and knowing how it varies in unconventional reservoir plays provides valuable information to accurately interpret hydraulic fracturing efficiency and microseismic response to hydraulic stimulation. Ultimately the goal is to evaluate the efficacy of these intervention and monitoring technologies in the context of production enhancement.

In this process, acoustic logs provide important inputs for determining geomechanical properties needed not only for hydraulic fracturing (e.g., Young’s modulus and Poisson’s ratio) but also to compute rock strength in order to utilize observations of wellbore failure to constrain in situ stress. The methods to derive these properties from acoustic logs are well understood in isotropic rocks, but have not been sufficiently investigated in unconventional or shale gas plays, which can have vertically transversely isotropic acoustic and mechanical properties. However, data acquired by modern multi-pole acoustic logging devices can be used to characterize these types of rocks provided core measurements (cut perpendicular and transverse to bedding) of rock strength and elastic properties are available for calibration.

Further details of the process of building a geomechanical model can be found in Zoback (2007) and in Moos (2007). As mentioned above, a key element of this process will be to assess the variability of stress magnitudes and rock properties along each well trajectory as this information is utilized to predict well ovality (i.e., stress-induced borehole breakouts) during drilling and completion to ensure successful packer placement for multi-stage fraccing. Figure 2 shows the results of an integrated analysis involving dipole sonic and acoustic image log analyses combined with petrophysics and algorithms to establish the ability to hydraulic fracture. This includes predicting how hydraulically induced fractures propagate in the reservoir in terms of orientation, what pressures are required, and if the induced fractures are likely going to be contained are additional key aspect to be addressed and are based on the GEM built for the unconventional reservoir. In Figure 2, we see from the radioactive tracer post-frac log (ninth track from the left) how induced fractures evolved during stimualtion. This matches the effect predicted by the petrophysical analyses shown in the other traces. Hence, having these types of data and doing such analyses in advance of the fracture design can obviously improve fracture optimization.

Note that elastic models typically used for the purpose of deriving stress profiles as a function of depth are often problematic unless they are well calibrated against direct determinations of stress magnitudes and orientations derived from evidence of stress-induced wellbore failures at selected depths. It is important to check the appropriateness of such approaches in unconventional gas fields. Figure 3 shows a more schematic example of how the various logs (both wireline as well as real time) and analyses are utilized to make informed decisions on packer placement and hydraulic fracturing. Intervals with borehole breakouts would be avoided for packer placement. Furthermore, it may be possible to optimize the drilling process in terms of mud design – both weight and composition – such that the breakout development is minimized or even entirely prevented

Finally, hydraulic fracturing the formation greatly improves reservoir performance by expanding the overall permeability volume due to the stimulation of the natural fractures - another aspect of studying and understanding unconventional reservoirs. In this respect integrating the GEM with knowledge on natural fracture occurrence in the reservoir – identified from image logs and core and in some cases augmented with seismic data to sample away from the wellbore – is key in this respect since natural fracture characterization is critical for construction of fracture models for stimulation and flow simulation. Understanding when natural fractures become stimulated (so-called critically stressed) and enhance permeability is monitored with microseismic surveys (as discussed further below) since each microseismic event indicates a shear fracture that has been displaced (i.e., its shear strength was overcome and it mechanically failed in shear). While in the context of unconventional reservoirs it is now generally accepted that stimulation in shale gas reservoirs occurs through a combination of shear slip and opening of pre-existing (closed) fractures and the creation of new hydraulic (tensile) fractures (Figure 4), Barton et al. (1995) have shown that it is the shear fractures that also enhance permeability most effectively (in particular post stimulation). Furthermore, these critically-stressed natural fractures outline the stimulated rock volume (SRV) – since they can be monitored by microseismic – in which permeability is enhanced and that is drained in the subsequent production (Moos, 2010). Drilling the well in the right direction in order to stimulate the maximum amount of natural fractures and associated reservoir volume is key for the success of unconventional reservoirs. A well-constrained fracture model makes it possible not only to model the effects of stimulation, but also to predict the change in flow properties during production as the reservoir pressure decreases. Hence, it is important to identify the optimal well trajectory to exploit fractures, either in their natural state or after stimulation. As can be seen in Figure 5, stimulation not only increases productivity but also causes a change in the orientation of the most productive well.

Well Design and Well Placement

This paper deals with cases where the reservoir is most economically developed with the aid of horizontal wells – these span a wide range of examples, such as the well-known Troll field in the Norwegian sector of the North Sea to the giant and super giant carbonate and sandstone oil and gas reservoirs of the Middle East, to the previously uneconomic gas shales in the US. The commonality of these reservoirs is that well productivity versus well cost is the key driver in well design. In low permeability or tight reservoirs, longer laterals access larger volumes of reservoir, which potentially offers higher productivity, predicated on accurate well placement within the “sweet spot” of the reservoir and the appropriate completions design for the well trajectory and the reservoir properties.

Well placement within the reservoir is crucial to ensuring production rates, which in turn are key to the economic success of a project. This requires proper pre-drill planning, based on existing reservoir, geological, and geomechanical models, a customized data acquisition program and real-time updates of the existing model based on the while-drilling data. Reservoir navigation decisions can then be taken in real-time, ensuring maximum reservoir contact of the horizontal wellbore. Over the last decade, the service industry has introduced numerous Logging While Drilling (LWD) sensors that provide formation evaluation data that can be used to accurately and reliably update the reservoir model in real-time. In conjunction with a precise rotary closed loop steering system and expert personnel, reservoir contact of up to 100% is a reality today. It should be noted that well placement needs to be addressed as a team effort – today’s directional drilling systems are capable of accurately tracking a very complex reservoir topography, ensuring maximum reservoir contact. This may, however, result in doglegs that make completing the well nigh on impossible – sacrificing a small percentage of reservoir contact to ensure completions can be placed across the reservoir as planned is definitely advisable.

Drilling fluids are also a key consideration although hydraulic fractures commonly extend past the damage radius, it is a key factor in hole stabilization and hole quality. Well directions should be determined with the key project objective of effective fracturing in mind, even if that means some loss of efficiency in drilling to ensure hole objectives are achieved. Any opportunities for qualifying initial assumptions and assessing risk by a correct data acquisition program ivolving cores, LWD or wireline logs are invaluable. It is critical for a caliper log to determine the optimum placement of isolation packers. In the case of fractured reservoirs or reservoirs which need to be fractured in order to enhance productivity, borehole image data is a crucial to being able to understand the stress field around the well.

Whether a batch drilling strategy is undertaken or not, the stimulation and drilling and completion should be kept separate. This is because both phases have unique resource requirements, and more efficiency can be gained by having the pumping equipment separate from the rig equipment. Additionally in some cases, the stimulation phase is separated from the testing phase for similar reasons.

Completion Design

Completions for horizontal wells are amongst the most challenging in the industry. Learnings from early horizontal wells in naturally flowing reservoirs proved that most of the production was in fact coming from the "heel" of the well and very little from the "toe", putting into question the need for long or extended reach horizontal wells. The introduction of novel completion techniques and technologies, such as open hole packers and Inflow Control Devices (ICDs), ensured uniform production along the entire length of the horizontal wellbore, enhancing production and improving recovery factors significantly (Figure 6). Our understanding of horizontal wells and how to complete them has been evolving quickly and continuously, spurred on by the introduction of new technology and better reservoir management practices.

Multi-Stage Fracturing – Concepts and Implementation

Hydraulic or acid fracturing is used to enhance the flow in low permeability reservoirs. It involves pressurization the wellbore sufficiently to overcome formation tensile strength and breaking it down, and forcing acid or other liquids into the (hydraulic or/and natural) fractures. In order for hydraulic fractures to stay "open" once the high pressure is released requires that proppant material is placed into these artificial fractures. The results of geomechanics studies will provide information on the preferential facture direction as well as predictions on fracture behavior during production and the associated pressure decline. As discussed above, pre-existing natural fractures can also be stimulated and contribute to flow post stimulation. Often these natural fractures prop themselves (Moos, 2010) and do not require proppant. This is one reason believed as to why stimulation with clear fluids is believed to be increasing production in shale gas plays in the United States.

Based on the successful experience with Reservoir Optimized Completions cited above, it was only a small step to the concept of "Multi Stage Fracturing" – separating or compartmentalizing long horizontal wellbores into zones and treating these zones independent of each other. The different components required to achieve the compartmentalization and customized treatment have been used in the industry for years – the innovation aspect in this case was the way these components were combined, adapting to the reservoir to ensure optimum reservoir access. Multi-stage fracturing has become a widely accepted completion technique in recent years with global applications and installations, but with the main focus on the prolific gas shales in the US, where thirty and more stages are used to drive productivity.

The technology used for this novel fracturing technique is typically modular and is based on proven packer and sleeve technology that has been utilized for decades. Multi Stage Fracturing equipment is commonly run as a one trip system on drillpipe and consists typically of a Liner Top Packer, multiple Open Hole Packers, multiple Frac Sleeves, a ball seat arrangement and Float Equipment all spaced out accordingly to the lateral interval length and permeability profile of the lateral. Figure 7 shows a typical hookup of such a system. The system is run in hole to total depth where the appropriate fluid is displaced in the open hole section followed by Liner Top Packer and Open Hole Packer setting sequence. After the Liner Top Packer is set, the hydraulic running tool is disconnected from the liner top packer and removed from the well. The open hole packers provide compartmental isolation along the horizontal interval while the frac sleeves are placed such that each stage is forming a pathway for stimulation fluid and production of hydrocarbons. The various equipment utilized will be discussed into further detail in the below paragraphs.

Liner Top Packers

Liner Top Packers come in many different varieties and are based on either Cased Hole Packer or Cemented Liner Hanger technologies with high load, pressure and high temperature capabilities. The main purpose of these systems is to successfully deploy the multi stage frac equipment to depth, allowing for rotation of the string if required and creating a final seal from the reservoir with the host casing. Figure 8 shows some of these options. Liner Top Packers are typically run on robust hydraulic running tools that allows torque and rotation to be transmitted into the complete Multi Stage Fracturing assembly in case hole tortuosity becomes a problem. It is important to understand the overall application to ensure that the correct equipment is identified and run. Hole tortuosity, well environment such as temperatures, pressures, challenging hole conditions etc. are all required to provide the optimum hardware configuration. One important factor that needs to be taken into account in all Multi Stage Fracturing completions is the expected treating pressures and absolute pressure differentials expected on the equipment and Liner Top Packer. The Liner Top Packer can be Isolated from fracturing pressure if desired by placing an open hole packer just below the host casing shoe. It is also sometimes desired to isolate the casing shoe directly as this is commonly seen as a weak point in the well.

Open Hole Packers

Open hole packers are strategically placed along the reservoir section to provide compartmentalization across the lateral spacing out the intervals to be fractured. There are two common types of open hole packers run and these are either a swellable packer or a hydraulic set packer that is usually based on proven Cased Hole Technology. The open Hole Packers provide compartmental isolation along the lateral section. The well environment has a huge influence on whether to run one packer or another type. Some of these conditions are bottom hole temperature, hole tortuosity, hole rugosity, doglegs etc. Often swellable packers require increased length to be able to withstand the treating pressures exerted on the packers during hydraulic fracturing. The main reason is that the durometer or the hardness of the packer declines when it swells, dictating the increased length requirements in order to achieve sufficient strength. There are two types of swelling packers available, however the most common one used is the one that reacts with oil based or hydrocarbon bearing fluids, which can be crude, diesel etc allowing the packer to expand out into the wellbore creating the zonal isolation required for the fracturing treatment. Upfront design work is required (Yakeley et al., 2009) to ensure optimum performance of the packer is achieved.

Hydraulic set packers have a lot of advantages over the swelling type packers, such as reduced length, easy to navigate through dog legs and an instant seal upon installation. However the hydraulic set packers do require a more in gauge hole then the swell type packers to be able to create an effective seal as the operating window is set. In other words, maximum sealing diameter is dictated by piston travel and with maximum piston travel and over gauged hole, there is a high likely hood that a seal would not be created. If good hole conditions exist, then the Hydraulic Set Packer is the preferred packer with an instant created sealing mechanism provided. Figure 9 shows both the Oil Swell and Hydraulic Set Type Packers.

Sleeves

Sleeve technology has significantly advanced over the years, especially when basic sliding sleeve technology is taken into consideration. The sleeves themselves allow for proppant to be placed behind pipe by providing a communication path between tubing and open hole annulus. The sleeves are relatively straight forward, however the ball seat arrangements and internal sleeve mechanism technology is differentiating the various systems available in today's market. Frac sleeves contain specifically designed ball seats that are pinned closed using shear screws when installed in the well. There are essentially two types of sleeves, the permanent locked open sleeve and Re-Closable Sleeve (Figure 10). The permanent locked open sleeve is held open typically by detent rings or locking rings, while the Re-closable Sleeve uses Selective Shifting Tool technology to close the various sleeves as required in case of undesired water or gas breakthrough in the respective fractured zone/interval. It is required to drill out the individual ball seats of the Re-closable Sleeve to allow the selective shifting tool to pass through all the sleeves. The major advantage of Re-closable sleeves is that in case of onset of water or gas, the sleeve can be closed, ensuring more uniform depletion and preventing a particular zone of dominating the gas or water cut. If required to re-stimulate a well again, then this is also possible with Re-closable sleeves.

Sleeve activation

Frac Sleeves and Frac balls have seen a considerable amount of change over the last few years with special emphasis placed on the ball material and the ball seat geometry. The ball and seat functions two ways: for one, it allows the sleeve to be opened providing conductivity to the fractured zone, and secondly the ball can provide isolation from the previous fractured zone. The type of material used for balls depends on the pressure differential requirements for the application, fluid/chemical exposure and if the ball requires to be landed on the seat with near maximum frac rates. The system pressure rating is depends on the combination of ball material and ball seat geometry. Different size frac balls (Figure 11) from small size upwards are used to land on corresponding seats where a pressure differential is created across the ball and seat, followed by an increase in tubing pressure resulting in the shearing of shear screws to open the sleeves and expose the frac ports. It is important to know the pump rates and types of frac fluid used to ensure that the frac sleeves are not accidently opened during the treatment. In some cases, the frac sleeves placed closest to the toe of the well will have a higher actuation pressure than those placed toward the heel of the well to compensate for the forces created during the fracture treatments.

The Ball Seats in the sleeves vary by application requirement. There are various ball seat configurations available from regular ball seat system with up to twelve stages, collapsible ball seat systems and dual seat ball seat systems with fracturing stages currently available up to 24 stages. Seats come with different pressure ratings available and this is mainly dictated by the type of ball used. When the number of stages increases up to 24 stages, the increments of the balls sizes are typically halved from 1/4" to 1/8" providing up to 50% less contact posing a challenge for the overall pressure rating of the system and typically reducing such rating. Collapsible ball seats are a good alternative to maintain the pressure rating of the overall system. Figure 12 shows the various ball seat arrangements/configurations currently available on the market. The balls are manufactured from a special low gravity material allowing the ball that was pumped down the wellbore to be flown back to surface where they can be captured by surface catchers in the surface piping system, but they also allow for accurate ball placement during treatment while at the same time being capable to withstand the pressures exerted during fracture treatment.

Operating sequence

A simplified high level operational sequence is described in the following paragraph. It is highly recommended to perform proper hole cleaning and reaming operations to ensure that the multi stage frac assembly can reach TD without issues. Typically a bit, roller reamers and some collars to simulate a stiff assembly is run, providing confidence that the completion equipment can be run to TD without issues. Once the hole has been conditioned to receive the multi stage frac assembly, the equipment is picked up with the shoe track consisting of a round bull nose, combined with dual float shoe and ball seat. The rest of the completion is then made up with the FracPoint Open Hole Packers and Frac Sleeves spaced out accordingly to the reservoir permeability and gauge hole criteria. Once all equipment is made up, its run on drill pipe to TD, where the assembly is spaced out prior to landing the completion. A setting ball is then dropped to close of the system followed by setting of the Liner Top Packer and other hydraulic equipment. The Liner top packer is then pressure tested followed by retrieval of the running tools. The upper completion can then be run followed by the rig moving of location. The Frac pumping spread can now be brought in to perform the actual frac operations by opening the pressure operated sleeve first directly followed by the fracturing treatment. The first ball is then pumped and the second stage can commence followed by the other stages as required. Once all zones have been stimulated, the well can be brought into production by either flowing back the balls to surface or to mill up the balls and ball seats.

This novel completion technique will continue to evolve by continuously pushing the operating envelope with regards to pressure ratings, well complexity and increased amount of stages. It is thought that this technology will continue to gain further acceptance in world wide applications. The success rate of the equipment is high and this will continue with the robust components and simplicity of the overall completion system.

Monitoring of Multi-Stage Fracturing – Concepts and Implementation

During the wellbore construction process and in order to place the well correctly in the reservoir, drilling and formation evaluation data is gathered and used to optimize processes, perform quality control and ensure the project objectives are met.

The same attention to detail and data gathering is required during the fracturing process. While Multi Stage Fracturing uses proven components and technologies, albeit in a more complex configuration, the use of downhole flow and temperature sensing is still gaining acceptance in both cased and open hole completion scenarios. This type of monitoring can be achieved either with Distributed Temperature Sensing (DTS) or with Permanent Down Hole Monitoring Systems (PDHMS), which are either electrical of fiber optic based. Both systems are combinable.

The combined application of DTS and PDHMS can provide huge benefits such as monitoring of pressure and temperature for the life of the well, flow assurance, provide details during well intervention, can determine flow rates from the independent zones when multiple gauges are installed, but can also provide very valuable data during frac placements, all in real time. This allows for on the spot changes for the following stages still to be stimulated.

Operators have already pioneered these two novel completion techniques with excellent results where data from DTS and PDHMS provided real time answers during installation, fracture treatment, zone contribution and flow profiling. The Sleeves and open hole packers used for these advanced Multi Stage Fracturing completions requires modifications to allow either a single or multiple control line bypass for the DTS line and PDHMS lines. (Figure 13) The Frac Sleeves require some of the ports to be blanked off to allow for the control line bypass, while a channel milled over the full length of the Sleeve insures the control line is fully recessed into the sleeve to insure the liners are below the major OD of the Sleeve to facilitate smooth running in the open hole. Cover plates are also installed to protect the lines during RIH and to protect during the fracture treatment. To date, a maximum of 24 stages can be run inside a 6-1/8” open hole dictated by the milled slots in the Sleeves.

Fracture propagation can be monitored with temperature sensing or with radiation logs, in case radioactive tracers were used. Another method is to use microseimic, where geophone arrays are used to monitor the shear failure along pre-existng natural fractures based on their acoustic signature. A conceptual model is shown in Figure 14. Micro-Seismic monitoring and temperature sensing can be carried out in real time as the first stage is treated. Results from the first treatment can then be used to evaluate the effectiveness and the fracture created, allowing subsequent zones to be stimulated with optimized pump rate, volume and pressure parameters.

Post Job Analysis – Learnings and Best Practices

At this stage, an After Action Review of the treatment and its effectiveness should be performed, comparing results to expectations. This should be superimposed on the fracture mapping obtained from the Reservoir Characterization stages. These inputs should be introduced to the Field development model and required well density values. This will directly impact Project success and overall profitability. Field development and well optimization have many variables for consideration. Production optimization would depend on the completion system’s capability for remote monitoring and actuation of downhole valves, whether for water shutoff or downhole chokes to normalize the drawdown across the lateral. Additionally, the inclusion of injection lines for production chemicals which may be needed at some period in the well productive life. Reservoir management will be assisted by the data acquired from downhole Pressure and Temperature gauges. Some completion systems will benefit from the inclusion of instrumentation to monitor compaction forces that may be exerted on the completion system, primarily in the later stages of depletion; these can be used to model the reliability of the completion.

Field management expertise is required to optimize production and maintain the production plateau for as long as possible. As secondary and tertiary recovery methods are limited with gas reservoirs, it is important to understand the additional stresses being introduced as the field depletes and review initial assumptions as the field enters the inevitable decline stages. Even in the termination stages, Project Management has a role to play in the re-sizing and decommissioning process of surface infrastructure.

Summary and Outlook

In this paper, we have presented an integrated approach to accessing gas in tight or unconventional reservoirs, based on project management, thorough planning and reservoir modeling, real-time data updates and model validation during the wellbore construction and completion phase and carrying forward into the reservoir stimulation phase. The importance of geomechanics for this type of project has been highlighted as well as the need for data acquisition during all phases of field development. We have illustrated the need for “feedback loops” in order to implement lessons learnt and best practices during all stages of the project. The technologies showcased in this paper have been in use in other shale gas and tight gas plays – with good success. While it is recommended to learn from these successful applications elsewhere, we have to bear in mind that all reservoirs are unique and that adapting these technologies to the reservoirs encountered in the Middle East is a challenge in itself. However, the oil and gas industry has a track record of success and with the introduction and adoption of new technologies and ideas, unconventional and tight gas reserves in the Middle East will be unlocked.

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Figures

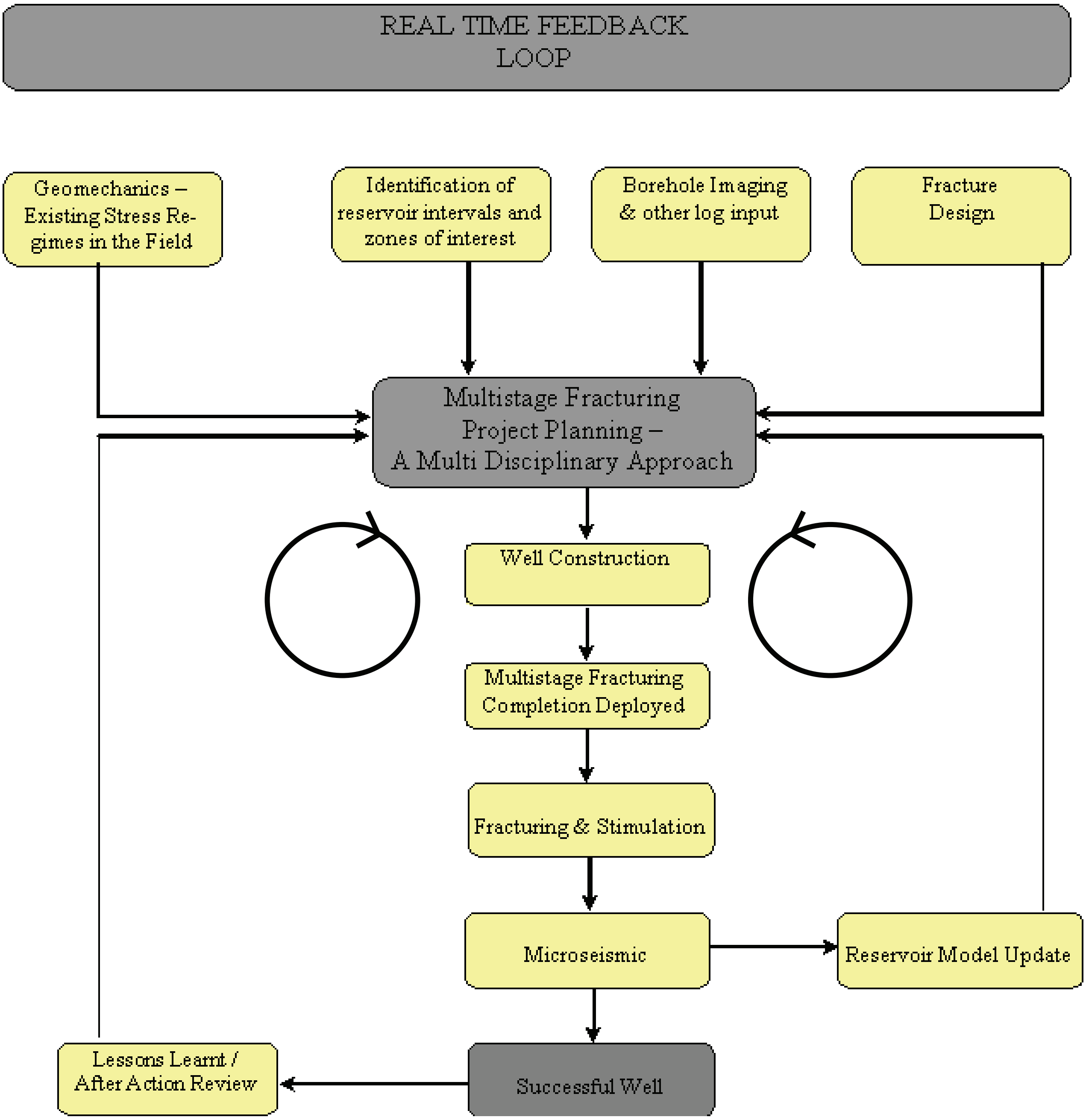

Figure 1: The workflow above demonstrates an integrated approach to successfully implementing a multistage fracturing system. Several feedback loops are shown to illustrate the Best Practices adopted based on After Action Reviews. The circles symbolize other feedback loops used in real-time during the wellbore construction process to ensure optimum well placement based on real-time updates of geological models.

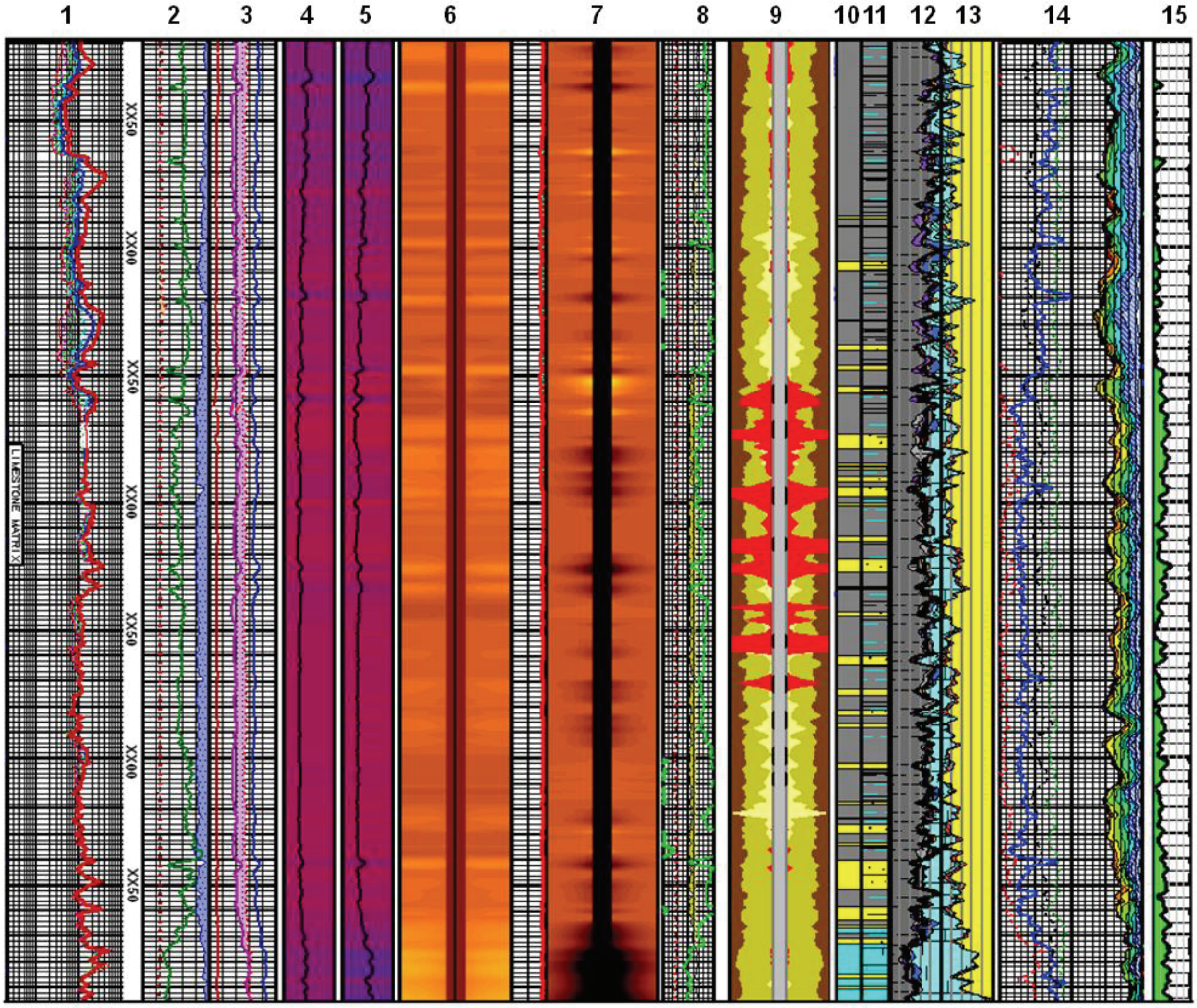

Figure 2: Integrated analysis involving dipole sonic and acoustic image log analyses combined with petrophysics and algorithms to establish the ability to hydraulic fracture [from LeCompte 2009]. Track 1: Resistivity curves; Track 2: GR-CAL-BIT and Density porosity shade in blue; Track 3: Openhole acoustics DTC (Blue), DTS (purple) DTSH (red dotted) and DTST (dark red). The VTI anisotropy is shaded in pink; Track 4: Fracture gradient profile assuming isotropic rock and no lateral tectonic strain model; Track 5: Fracture gradient profile using the VTI anisotropy and lateral tectonic strain; Track 6: Radial shear wave profile - Absolute DTS values (from borehole wall up to 2 ft into the formation); Track 7: Radial shear wave profile - Relative change (from borehole wall up to 2 ft into the formation); Track 8: GR and CAL (repeat); Track 9: Radioactive tracer logging (Post-fracturing). Perforated intervals in black. Scandium in light yellow. Iridium in red, Vsh in brown; Track 10: General lithology form Rockview expert system; Track 11: Specific lithology form Rockview expert system; Track 12: Lithology weight volume from Flex; Track 13: CNC (red), Density porosity (blue), MNR total porosity (black dotted); Track 14: MREX apparent T2 NMR partial porosity; Track 15: Total organic matter TOC from Rockview.

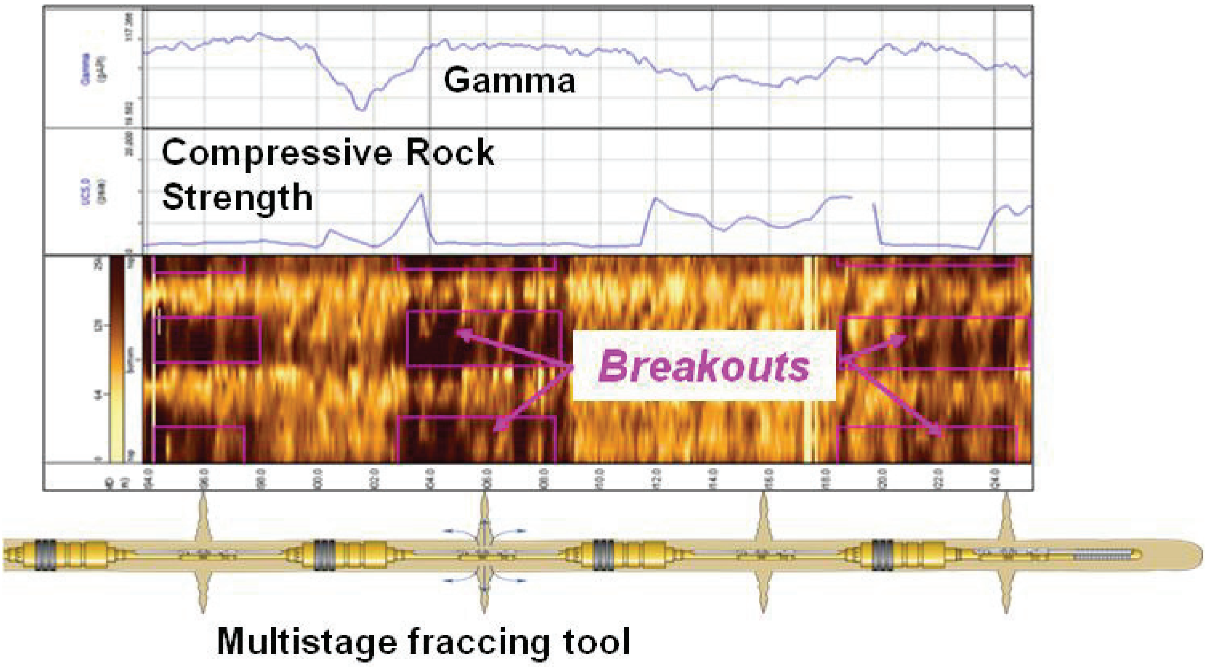

Figure 3: Schematic example for open hole packer placement guided by rock properties (gamma ray and compressive rock strength) and realtime images to detect stress-induced compressive borehole failures (i.e, borehole breakouts).

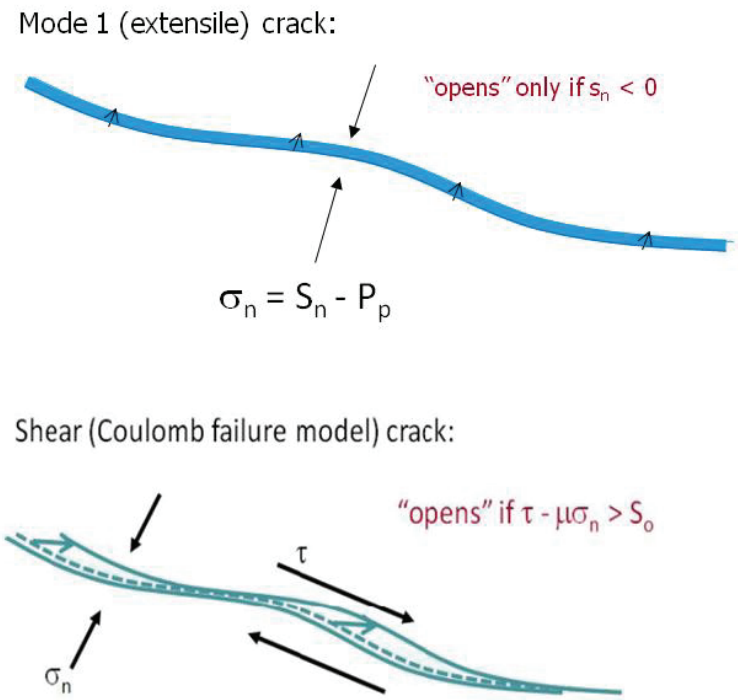

Figure 4: Stimulated fractures can fail either by shear slip, which offsets rough fracture walls leading to a permanent change in fracture properties, or by opening, which cannot cause a permanent change unless the fracture is subsequently propped open by rubble created by slip or by proppant, which must be carried by the fracturing fluid. If natural fractures are sufficiently weak and appropriately oriented, shear failure will occur before the pressure is large enough to open new hydrofractures. Figure from Moos (2010).

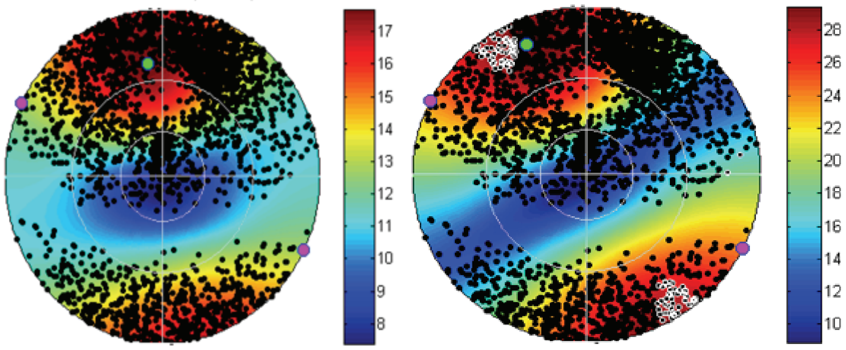

Figure 5: Poles (lines perpendicular to fracture surfaces) of natural fractures intersected by the well on a lower hemisphere stereographic projection, superimposed on predictions of relative well productivity prior to (left) and after (right) the stimulation shown in Figure 1. White dots are the stimulated fractures; green is the optimal well orientation.

Figure 6: Comparison of reservoir drainage for natural flow reservoirs in standard open hole completion (upper) and reservoir optimized completions (lower), which use open hole packers (black) to segregate the lateral wellbore into three compartments. Hatched areas are inflow control devices adjusted to formation permeability profile along the wellbore.

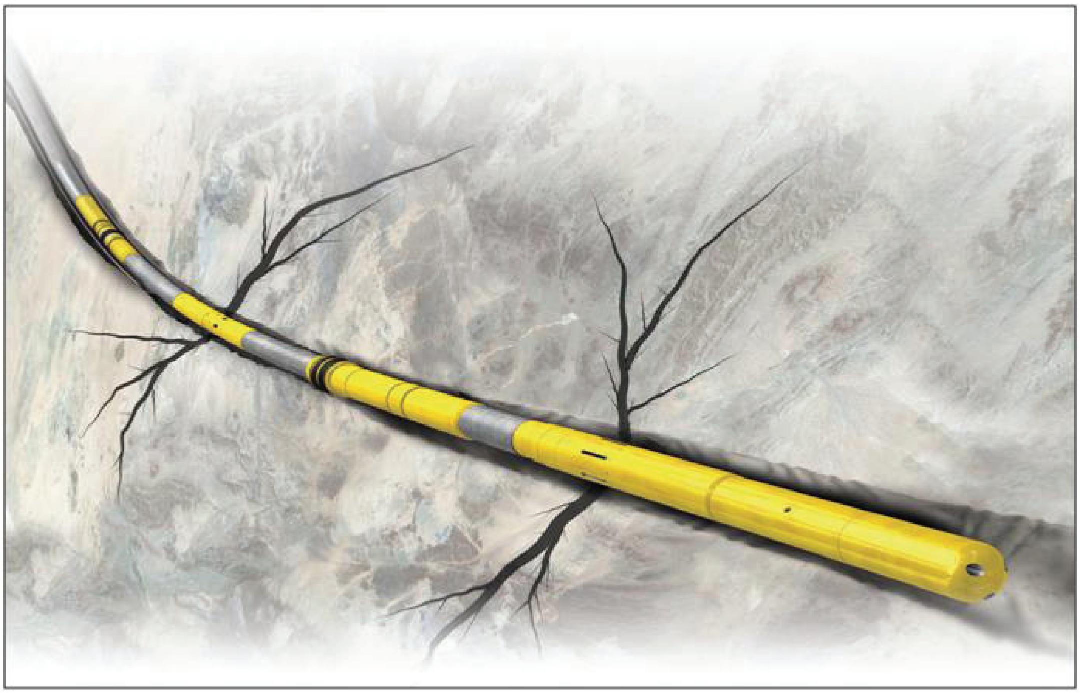

Figure 7: Multi Stage Fracturing equipment is commonly run as a one trip system on drillpipe and consists typically of a Liner Top Packer, multiple Open Hole Packers, multiple Frac Sleeves, a ball seat arrangement and Float Equipment.

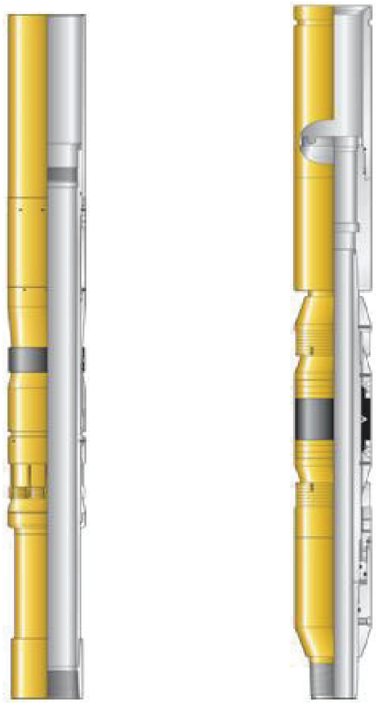

Figure 8: Liner Top Packers come in many different varieties and are based on either Cased Hole Packer or Cemented Liner Hanger technologies with high load, pressure and high temperature capabilities.

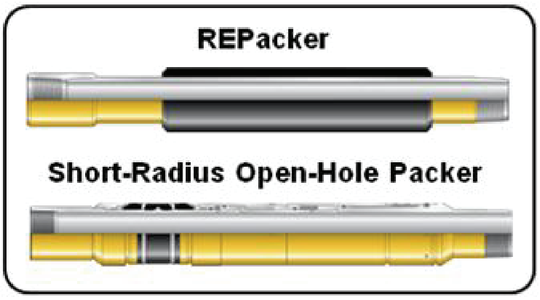

Figure 9: Two most common types of open hole packers run are either a swellable packer or a hydraulic set packer that is based on proven Cased Hole Technology.

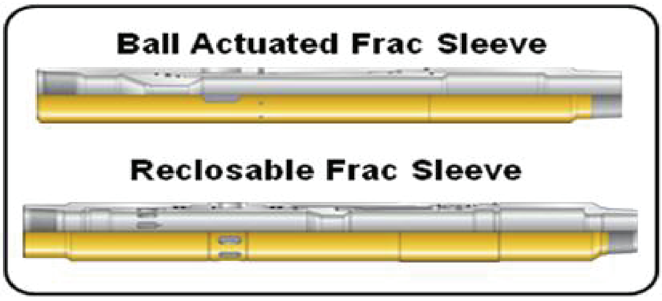

Figure 10: Frac sleeves can be divided into two types of Sleeves, namely a permanent locked open sleeve and re-closable sleeve.

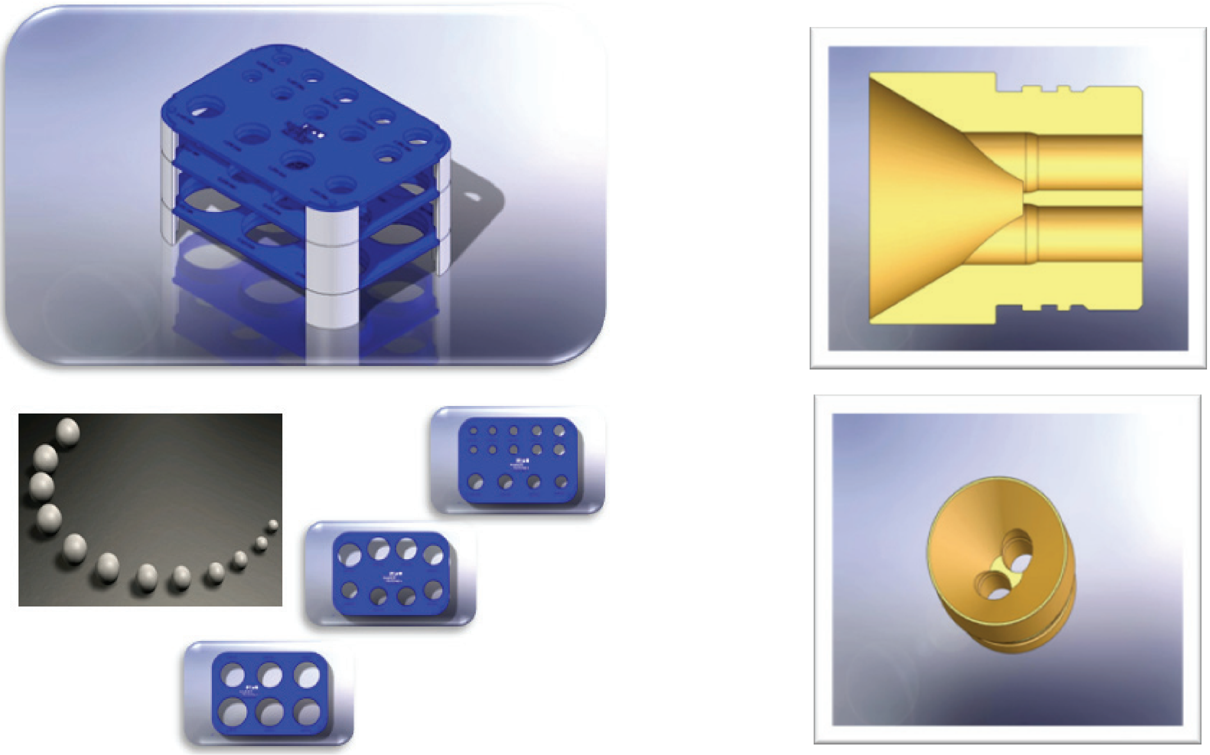

Figure 11: Different size frac balls from small size upwards are used to land on corresponding seats where a pressure differential is created across the ball and seat to open the sleeves and expose the frac ports.

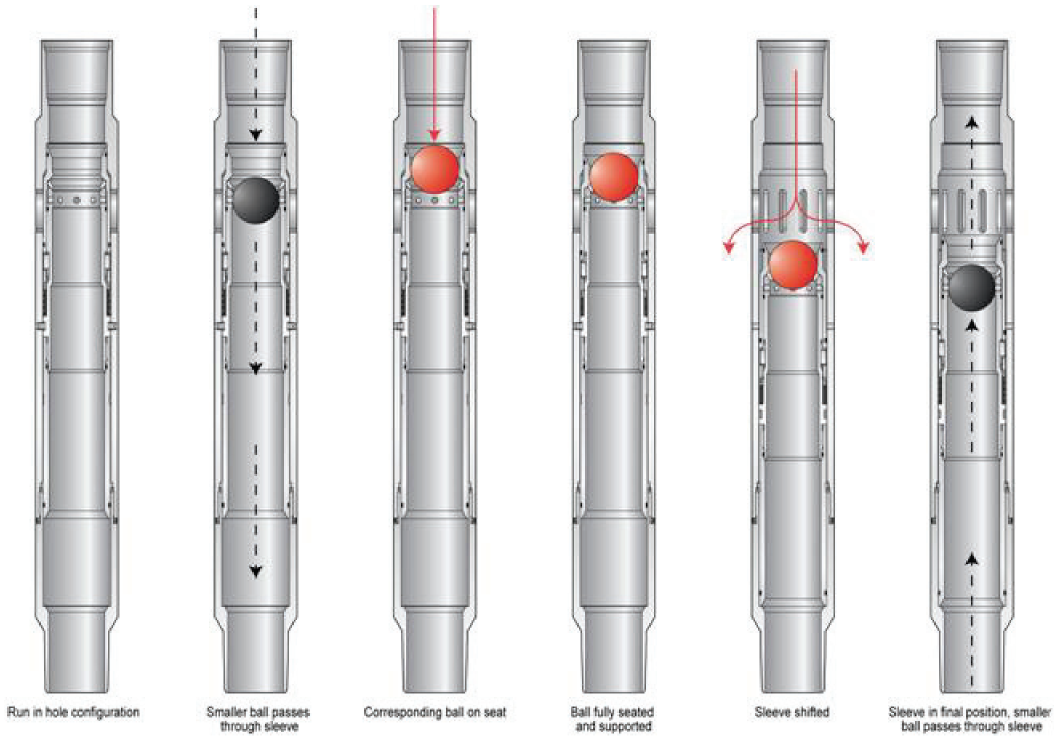

Figure 12: Various ball seat configurations are available from regular ball seat system with up to twelve stages, collapsible ball seat systems and dual seat ball seat systems with fracturing stages currently available up to 24 stages.

Figure 13: Sleeves and open hole Packers used in advanced Multi Stage Fracturing completions requires modifications to allow either single or multiple control line bypass for the Distributed Temperature Sensing (DTS) line and PDHMS lines. The photographs above show actual testing in the laboratory and field installation.

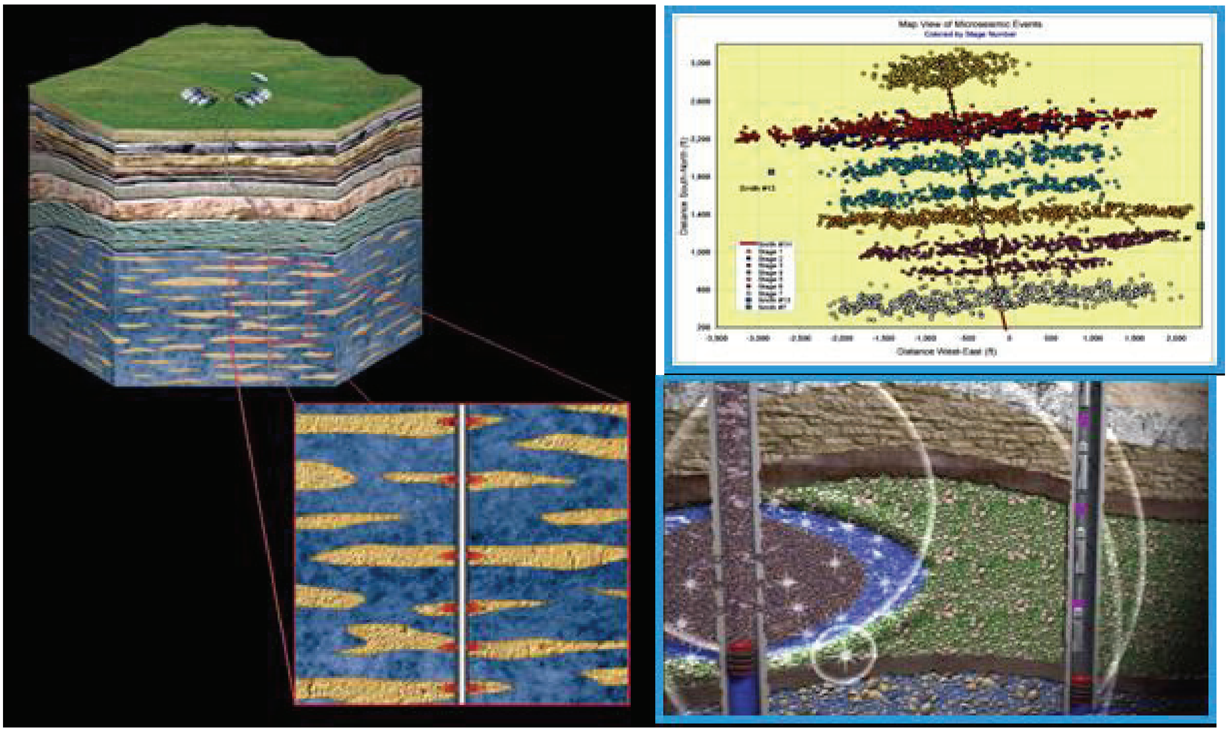

Figure 14: Conceptual sketch of frac operations and Microseismic data integration. Fracs are initiated in the well in various zones, micros-seismic sensors are located in observation wells (upper right) and microseismic plot (bottom right) is used to evaluate frac height and orientation.