Enhanced Techniques for Multi-Zone Stimulations and Completions

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Abstract

Economic production from many low permeability unconventional reservoirs has been enabled by the ability to propagate multiple stimulation treatments per well and from multiple wellbores located on a single pad or platform. A variety of design procedures and mechanical means have been developed to create improved connections to the reservoir, reflecting ongoing innovation in improving stimulation effectiveness while enabling reliable treatment placement and completion cost reduction. Both modeling and interpretation tools have been developed to predict, assess, and optimize stimulation treatment design and placement.

Successful multi-zone stimulation requires evaluation and selection of many options - ranging from rock property design assumptions to methods of zonal isolation and fluid diversion to the efficient use of water and equipment deployment. Hence it is essential to incorporate strategies to integrate multi-disciplinary technology, operational data, and economic optimization in the workflows to achieve the best results. These strategies also require the flexibility to adapt various existing and emerging technologies within the unconventional reservoirs and account for the local operating environment and conditions.

This paper examines the fundamental elements driving multi-zone stimulation effectiveness based on integration of extensive field experience and research in reservoirs requiring multi-zone stimulation to unlock their economic potential. Tools and workflows will be illustrated that have improved multi-zone stimulation effectiveness, enabled significant operational efficiencies, and have led to enhanced well performance and resource recovery.

Introduction

Worldwide, substantial oil and gas resources are contained in low permeability formations. Many of these resources are characterized by thick intervals and/or multiple reservoir targets. In addition, some form of stimulation such as matrix acidizing, proppant fracturing, or acid fracturing is required to effectively and optimally produce these resources. However, the increased geologic and reservoir heterogeneities present in these resources can lead to substantial complications to the stimulation treatment operations, and reduction in stimulation effectiveness. To address these issues and enable more efficient resource recovery, during the last decade, ExxonMobil has focused on developing fit-for-purpose design methods, completion systems and procedures to enable optimization of stimulation treatments.

Unique stimulation challenges can arise when hydrocarbon resources are comprised of multiple vertically distributed discrete reservoir intervals contained in long productive intervals or when targeting “tight” reservoirs with horizontal wells having extended lateral sections in reservoirs possessing significant heterogeneity. The overall challenge is characterized by the need to effectively manage a balance between the number of stimulations performed, stimulation treatment quality, cost, and the overall reliability of treatment placement and execution. Within the context of current stimulation technology capabilities, the management of this balance can result in operators intentionally bypassing less attractive hydrocarbon intervals, incurring lower production due to poor stimulation effectiveness, labeling resources as uneconomic based on the cost required to adequately access the reserves, or encountering operational difficulty in achieving reliable and effective treatment placement. During the last decade, extensive research and field experimentation enabled the development of unique workflows, modeling capabilities, and stimulation methods for tight sandstone, shale, and carbonate formations. As shown in Figure 1, an integrated technology platform, combining advanced reservoir and geo-mechanical modeling with field-based experimentation using appropriate technology and diagnostics can enable fit-for-purpose hydraulic fracturing solutions and the ability to optimize development of “tight” resources across many different reservoirs.

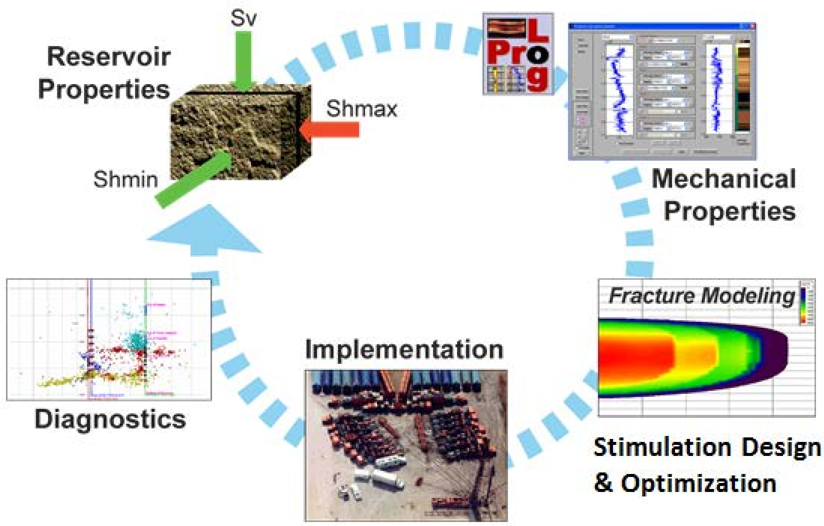


Figure 1. Integrated workflow to enable continuous improvement in optimizing economic outcomes.

Many large resource opportunities are characterized by thick intervals and multiple reservoirs (Table 1). These assets vary from tight gas produced from very low permeability sandstone reservoirs to conventional gas and oil produced from low to high permeability carbonate reservoirs to heavy oil produced from unconsolidated sandstone reservoirs. Despite the wide differences, these developments share two common features - very thick producing horizons and the requirement for effective formation stimulation of the reservoir targets. Historically, stimulation treatments have been successful in increasing well productivity; however, its importance is elevated dramatically for developments that require stimulation of the wells during initial completion. Without stimulation, such developments would be less profitable or in some cases not viable. Proper placement (or "diversions") of the stimulation treatment is perhaps the most important aspect of stimulation once the appropriate fluids and materials have been identified. Long intervals, regardless of stimulation method, make treatment placement even more challenging.

Field Examples	A	B	C	D	E
Formation	Shale	Tight Sand	Carbonate	Carbonate	Unconsolidated Sand / Diatomite
Production Fluids	Gas / Oil	Gas	Gas	Oil	Heavy Oil
Permeability range (md)	0.0001 to 0.005	0.001 to 0.1	0.1 to 100+	0.1 to 100+	100-5,000+
Gross Thickness (ft)	~20 – 1500+	~50-ft - 5000+	~500-1500	~50-1,500	up to 1000
Horizontal (ft)	~2,000-10,000	~3,000-5,000	~3000	~10,000 +	Mostly vertical

Table 1. Examples of formation characteristics that require multi-zone stimulation.

Hydraulic Fracture Stimulation Design Methodology

The elevated significance of stimulation treatments in unconventional reservoirs then drives the need for more focus and attention to integration of all available data in the design methodology, optimized design workflows, and improved methods for control of treatment placement. The stimulation design methodology revolves around identification of the optimum completion scenario for the given reservoir conditions and local situation. Compared to conventional reservoirs, unconventional reservoir with low matrix permeability, low porosity and high water saturation may be more prone to potential damage and flow impairment mechanisms.

Extensive field experience and measurements show the effective fracture volume is always less than the induced one. The rock is anisotropic and heterogeneous. In some cases, simple "bi-wing like" fractures may be induced if the stress anisotropy is high; alternative fractures could be complex clusters with low anisotropic stress state. It is crucial to determine optimum completion scenarios including horizontal longitudinal, horizontal transverse or multi-zone vertical stimulations (shown in Figure 2). Better understanding of the fracture initiation and propagation mechanisms enable development and deployment of new stimulation methods that may simultaneously lead to reduced cost and improved recovery.

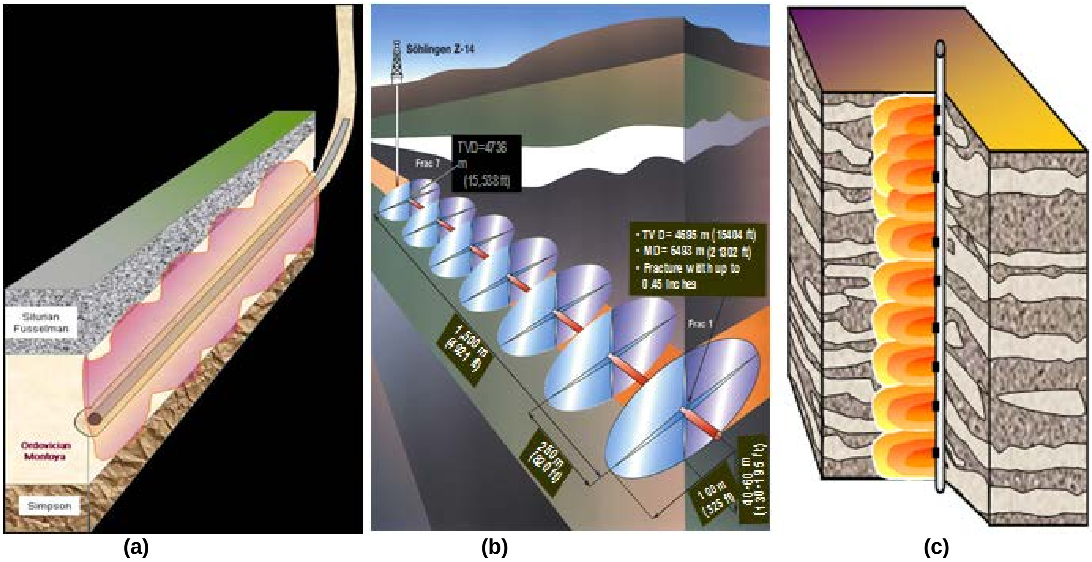


Figure 2. (a) multiple longitudinal acid fractures; (b) multiple transverse propped fractures; and (c) multi-zone vertical stimulations.

A unique set of software tools and integrated design workflows are used to develop and optimize the stimulation treatment design. The first step of the design is to select the appropriate optimum completion, target zones, and stimulation sequence using available analog(s) based on the field information including reservoir characteristics.

For example, in Piceance Basin (Colorado, USA) the gross reservoir thickness can be more than 5,000-ft, while the reservoir targets are isolated lenticular sands distributed throughout the section. For this application, s-shaped pad wells drilled from a single surface location are used, with gross target interval being penetrated by a vertical well, and stimulated with dozens of hydraulic fractures targeting the sands.[1,2] Deviated wells with selective placement of multiple fractures have been completed for example in Germany and Wyoming where the gross reservoir thickness is less than approximately 1,000ft (using various approaches such as the perf & plug method, limited entry designs, and un-cemented casing technology). In other applications, for example, many of the shale plays in North America (Table 2), the gross reservoir thickness is less than 400-ft, and horizontal wells with multi-transverse fractures used to enable effective resource capture. As another example, in the Permian Basin (Texas, USA), longitudinal fractures are used in horizontal wells (reservoir thickness less than approximately 100-ft).

Shale ID	Depth, ft	Thickness, ft	Fluid Type
Barnett	7000-8500	300-400	Gas
Fayetteville	5000-6000	100-200	Gas
Bakken	9500-11000	50-300	Oil
Eagle Ford N	4000-6000	100-150	Oil
Eagle Ford S	7000-9000	100-200	Gas
Haynesville N	8000-10000	200-300	Gas
Haynesville S	12000-15000	100-300	Gas
Marcellus N	5000 -6500	50-200	Gas
Marcellus S	8000-10000	100-300	Gas

Table 2. Examples of shale reservoir analogs.

An example of the candidate selection methodology for identifying preferred completion architecture which considers the effects of both the gross reservoir thickness as well as the net reservoir within the gross target interval is shown in Figure 3.

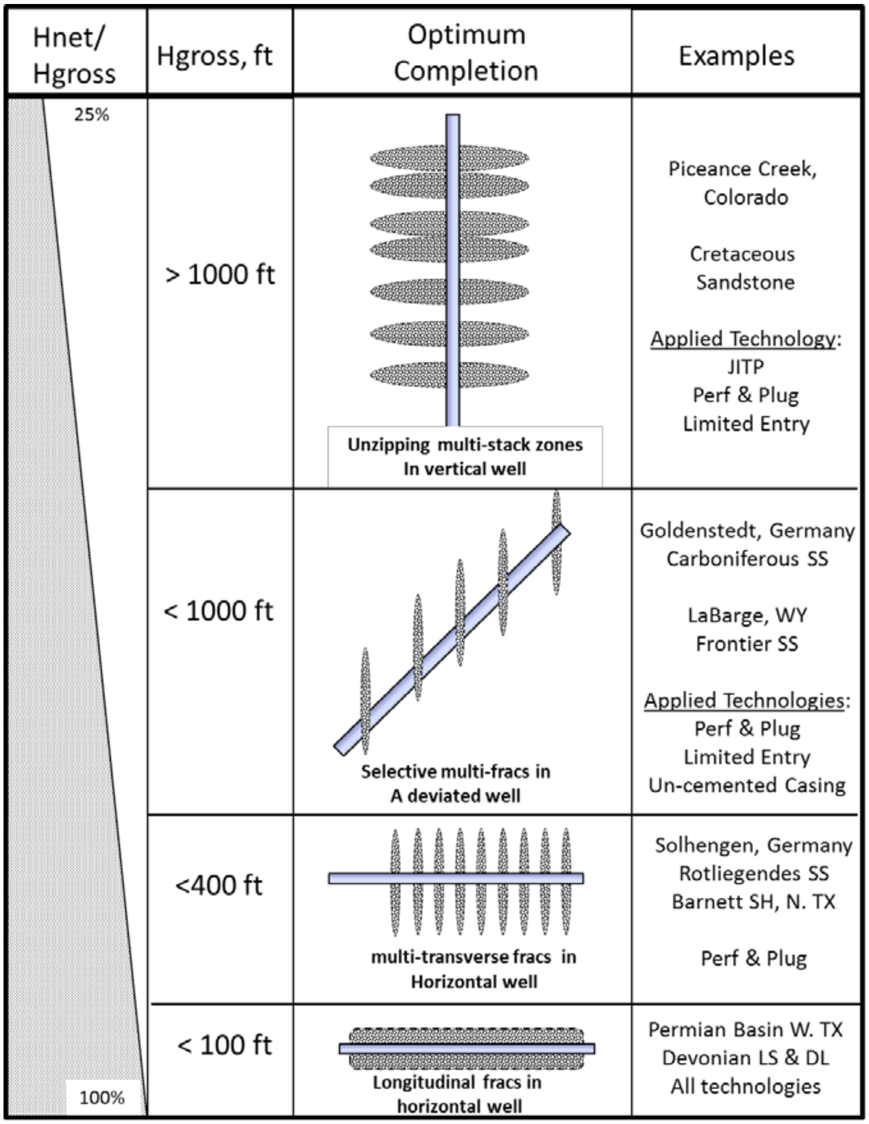


Figure 3. Optimum completion design with examples

Figure 4 shows a representative workflow for selecting and designing the completion and stimulation applicable to any unconventional resource. The appropriate stimulation design is based on consideration of the reservoir depth, thickness and hydrocarbon fluid type. If an analog application exists, then completion, stimulation, and production data would be collected and compared with reservoir properties (e.g., pore pressure, permeability, etc.). If the properties are similar to the analog, then the approach involves integration of all the available data from the analog to design the new well. If a suitable analog does not exist, more data may be required to be collected in the new well during the initial drilling phase (e.g., open-hole logs, conventional core, sidewall core, etc.). The necessary information for the detailed fracture design like log data, core testing data, relevant completion technology designs, etc. are then gathered and evaluated. Irrespective of analog availability, use of all available data will be important to reduce cost, increase productivity and improve recovery.

Early data collection in unconventional tight reservoirs is essential for assessment, development, and stimulation optimizations. It is important to determine the most likely fracture geometry (height, length, and location) combined with reservoir properties, and pay continuity to optimize the completion scenario for development. In the early phase, integrated datasets that capture a range of geologic, reservoir, and rock property data are extremely valuable for enabling robust stimulation designs.

A range of information is captured with development of these integrated datasets, and can include:

1. Open-hole and cased hole logs in new wells and available offset wells: such as gamma ray, resistivity, water saturation, water-filled porosity, neutron porosity, sonic, density and clay content, formation micro-imaging, calipers, cement-bond, production logs, and importantly gas or oil shows.
2. Reservoir pressure and stress distributions: including drilling mud log data, MDT measurements, lithology distribution for calculation of overburden gradient, and evaluation of minimum and maximum horizontal stress distributions.
3. Core and cuttings data: considering conventional core, sidewall cores, and cuttings analysis for use in calibrating log information.
4. Identification of depleted zones, water sources, reservoir intervals (top/bottom), hydrocarbon types and distributions;
5. Understanding of faulting and fracturing conditions within the target reservoir: leveraging available data such as micro-seismic or tilt-meter fracture mapping and available seismic data;
6. Lost returns information from offset wells; and
7. Well design scenarios, leveraging analog well information and logs.

Limited or partial data availability for design is a very common occurrence, especially during the early exploration stage of the field. When limited data exists, available analogs, empirical correlations, and/or relevant data need to be integrated, correlated to obtain necessary information and extensive sensitivity studies are conducted. It is equally commonplace to have multiple sources for single data and/or superficially contradicting data emphasizing the need for physics-based, integrated and optimized workflow even at the stage of data preparation for stimulation design.

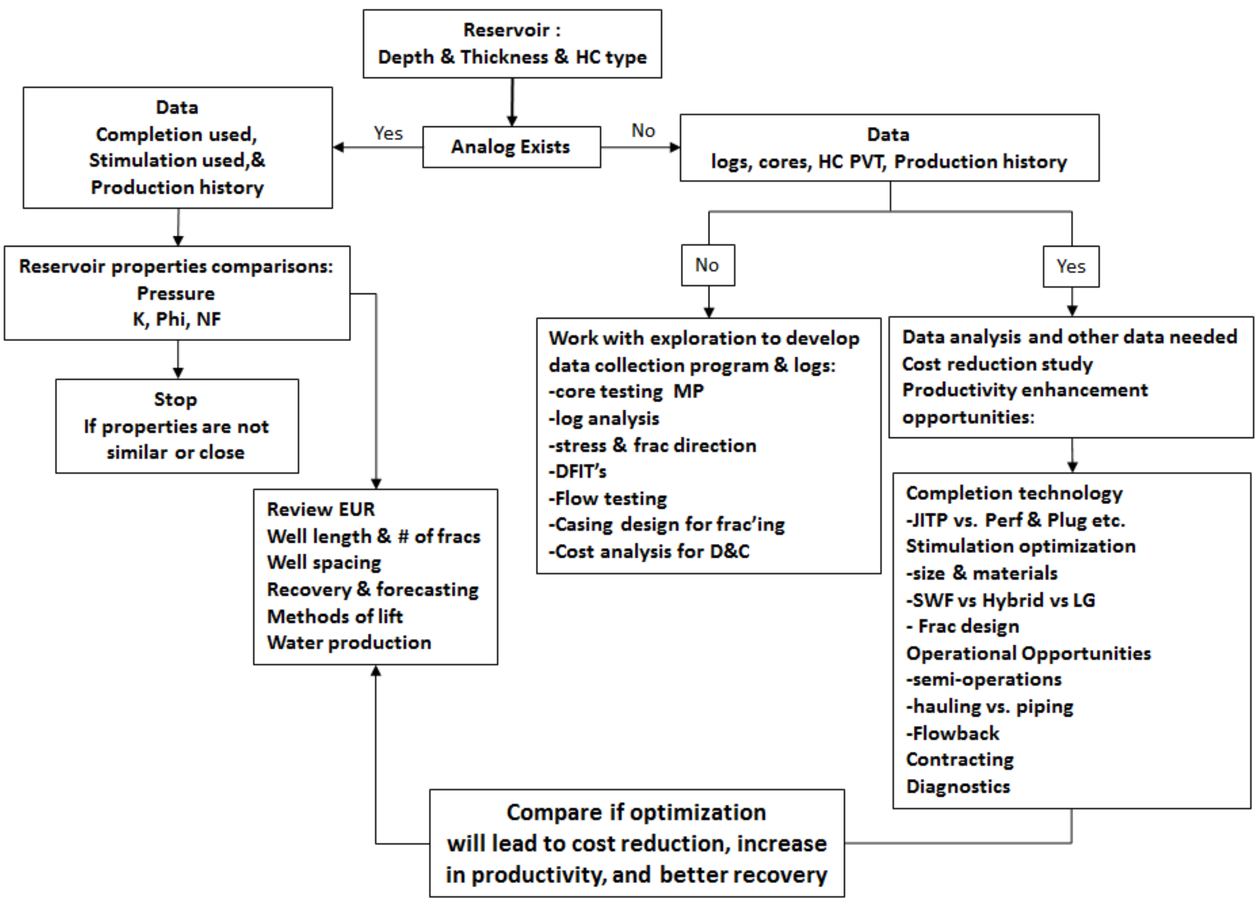


Figure 4. Workflow for completion of unconventional resources (NF-natural fracture; SWF-slick water; LG-linear gel; DFIT=Diagnostic Fracture Injection Test).

With the optimum completion scenario and all available data, a unique software "ProLog" has been developed and is used to analyze and integrate all information including petrophysical, geological, core test data, correlations to prepare high confidence rock properties, stress information with physics based layering approach for optimization. Based on availability of data or rather lack of it, advanced models related to scaling (up and down), rock physics models, dynamic-static mechanical property correlations, averaging techniques, etc. are regularly used to create complete high-confidence input for the stimulation treatment design. In-house rock properties correlations were built based on experimental results.

Figure 5 shows typical example workflows to build a geomechanical model necessary for a hydraulic simulator to predict the fracture geometry including the fracture length and height under two different scenarios. The workflow described in Figure 5(a) is only used when analog information is insufficient or no log data are available. The rock mechanical properties are calculated directly from the correlations/analogs from offset wells and used to generate the necessary geomechanical model. The workflow described in Figure 5(b) is used when limited or typical log data are available. The "Property Module" is critical part of the workflow and performs the rock physical model prediction and calibration (shown as green in Figure 5(b)). Several rock physics models are available in this module including the commonly used Xu-White model.[3,4]

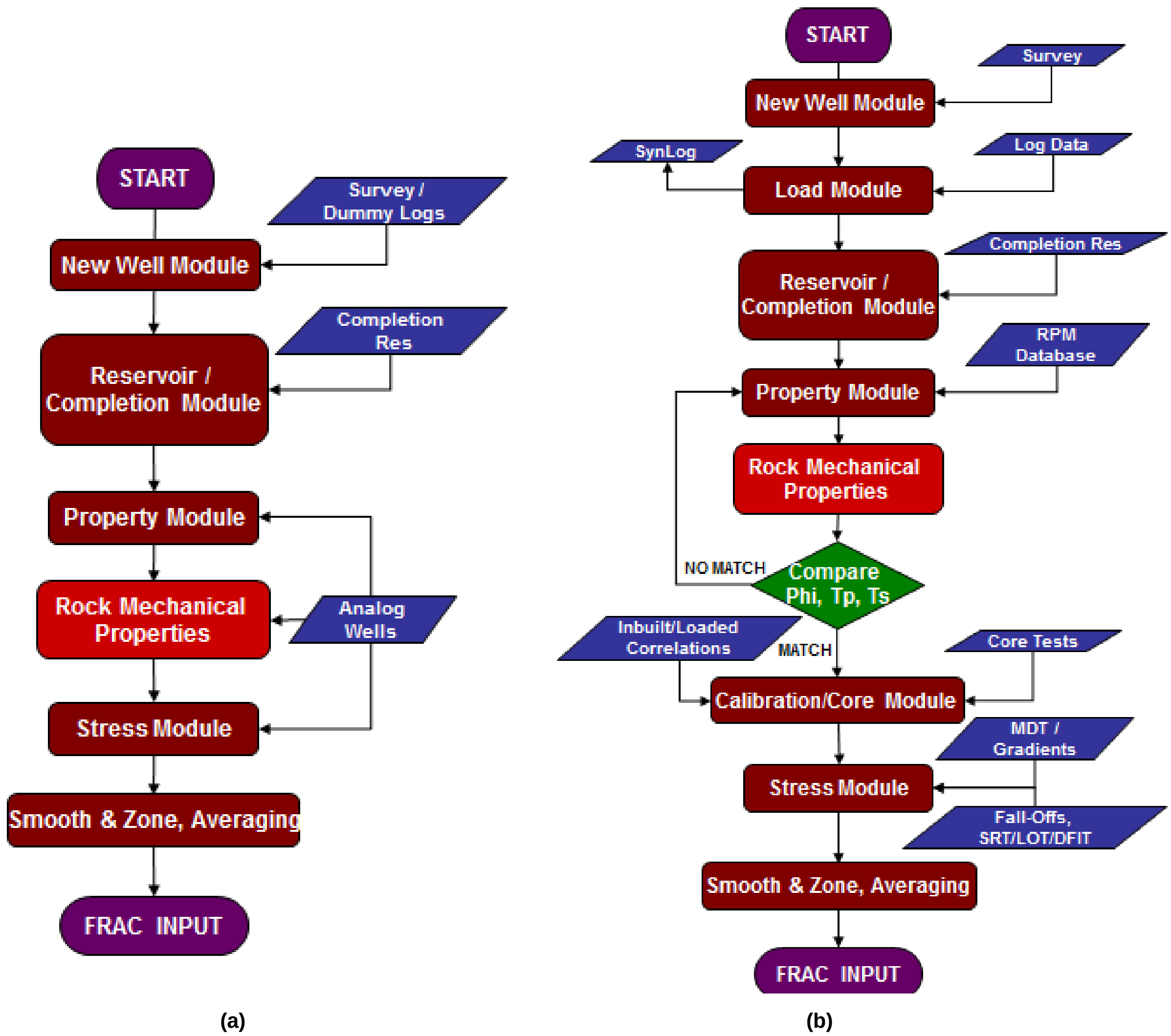


Figure 5. Example of workflow in ProLog: (a) Analog based analysis; (b) Log data based analysis.

Figure 6 is representative of an average porosity and sonic log match using a calibrated rock physical model. Typically the calibration is validated using multiple well data and quantitative means of comparison of measured and modeled data. The workflow depicted here involves use of a rock physics model due to lack of sonic log.

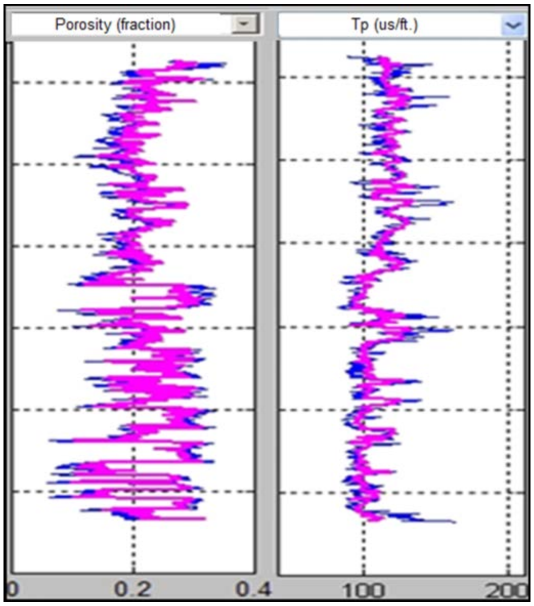


Figure 6. Porosity and sonic calibration of the rock physics model.

If the sonic log is not available, the "SynLog Module" in ProLog can be used to generate the synthetic well logs required to obtain the sonic logs using the information like well logs, relative location (shown in Figure 7), and other geo-model information from analog wells. The sonic logs can be used to obtain information necessary for fracture design through appropriate workflow in the stress module. The stress information and the rock properties are post processed through other modules to create the necessary input for fracture modeling. Proprietary and physics based methods are used for tasks like dynamics to static conversion of properties, creating property based layers, upscaling the log resolution data to layer resolution scale using property and application specific averaging techniques, etc. Certain time-consuming components like rock physics model calibration, upscaling, etc. are automated for quick turn-around time and facilitating sensitivity studies. Sensitivity studies are conducted for each variable with uncertainty to optimize the fracture design.

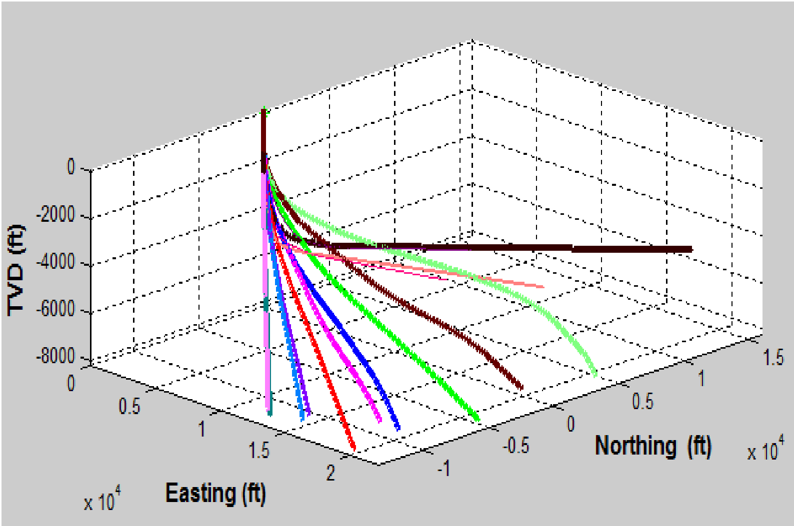


Figure 7. Spider plot shows the relative position of each well.

Figure 8 shows a fracture modeling result indicating that the propped fracture has good coverage in the pay zone. Following is the list of optimizations conducted during the hydraulic fracture stimulation design: optimization of treatment schedule, fluid rheology / density / friction and proppant properties including size and embedment properties; number of fractures and location, zone selection and isolation.

Other important considerations to maximize productivity are possibly to limit fracture growth to avoid potential water productive zones; treatment designs to maintain fracture containment within the target zone; and fracture design to potentially cover multiple productive zones that are adjacent and close proximity to each other. Design optimization may be down to effectively to minimize the cost. Finally, the recovery prediction is obtained based on obtained fracture design geometry in conjunction with economic analysis.

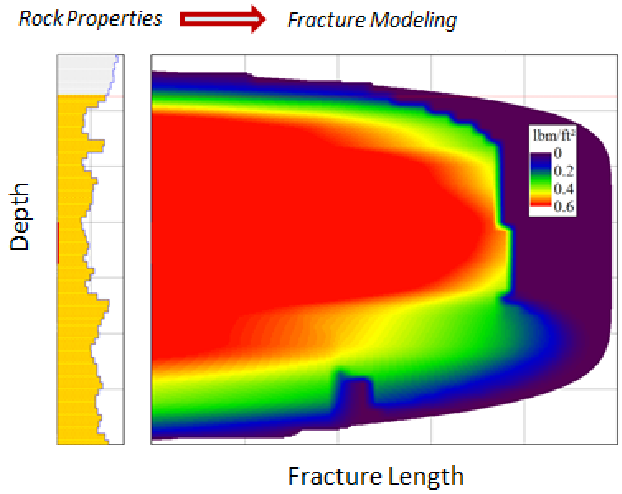


Figure 8. Example of a fracture model calculated fracture geometry.

Implementation & Diagnostics

With understanding of the desired design outcome, the significant challenge is to effectively achieve this in field implementation using reliable and efficient methods. Very common completion methods for stimulation of thick intervals or multiple reservoir targets include the "limited entry" method or "perf-and-plug" method and can be applied in vertical, deviated, or horizontal wells as conceptually illustrated in Figure 9. Details of this type of design approach are well documented in the literature. It has been used extensively in stimulation of lenticular tight gas sands in the United States and has evolved to be the preferred method for the majority of horizontal shale completions in North America due to the operationally reliability associated with treatment placement.

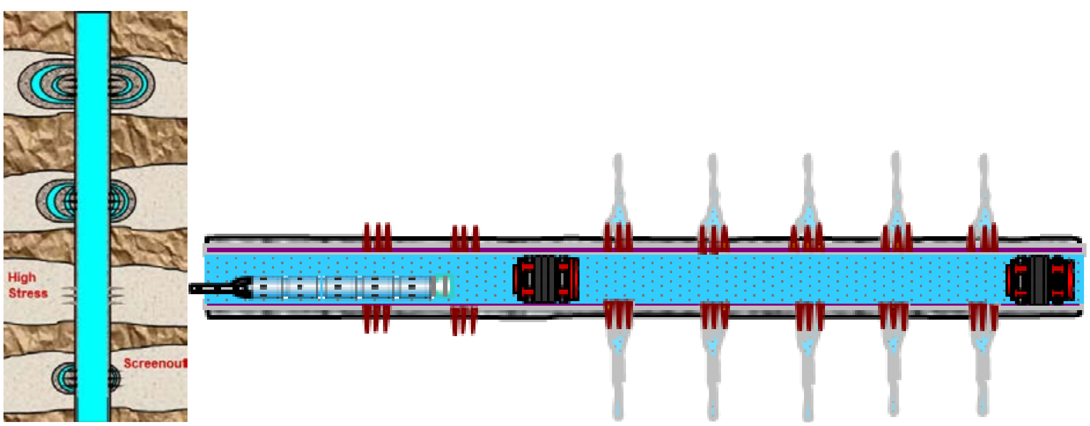
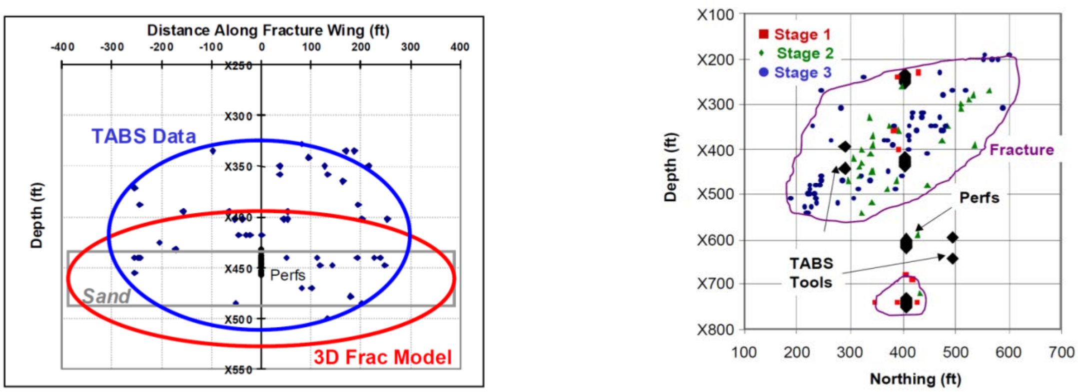


Figure 9. (a) example of a limited entry designed hydraulic fracture treatment in a vertical well with significant stress contrast between zones such that it is problematic to stimulate all targeted zones; (b) an example of a "perf and plug" horizontal well completion with multiple fracture treatments propagated in a relatively homogenous interval.

While these methods are widely preferred for operational reliability, the effectiveness of treatment placement may be reduced if there is substantial formation or reservoir heterogeneity present. A key diagnostic that has enabled improved understanding and development of improved design approaches and new stimulation approaches is a microseismic fracture mapping tool that uses acoustic methods to infer the geometry of induced hydraulic fractures.[5] This tool may be run in the treatment well during fracturing, or it can be used in one or more offset monitoring wells. This tool, "TABS" for Triaxial Borehole Seismic, consists of an array of three triaxial geophone receivers, a telemetry sub to transmit the data to surface in real time on conventional seven-strand wireline, and an interface to a gyroscopic survey tool to provide the tool orientation when clamped.

Figure 10 (a) shows how this type of microseismic data can be useful to calibrate and tune fracture models for design purposes when integrated log and core may not be readily available or when there is limited experience in the local area. In application in a low-pressure oil well, both a gelled frac and a proppant treatment were monitored. The fracture grew substantially above the top of sand into a shale interval. The envelope of TABS data shows less length and more fracture height development than predicted by the fracture model. In another application, as shown in Figure 10(b), TABS monitoring was performed from offset wells to examine a limited entry hydraulic fracture treatment design. In this application the vertical well had four open perforated intervals, with a limited number of perforations. The microseismic data suggests the majority of the treatment was placed within the upper portion of the targeted interval, with a significant portion of the lower portion of the targeted interval poorly contacted by the fracture treatment.



(a) (b)

Figure 10. Example of microseismic measurements in (a) single-zone stimulation; and (b) multi-zone stimulation of a vertical well.

Industry is also starting to gain substantial insights from production logs obtained in horizontal wells that have been stimulated using various techniques. In a unique dataset considering over one hundred production logs obtained in horizontal wells stimulated using the "perf-and-plug" approach, the data clearly indicate a substantial percentage of perforation clusters may not be effectively flowing in each well. [6] This can be due to a variety of reasons, including poor diversion of the stimulation treatment, reservoir heterogeneity, or by excursions out of the targeted zone during drilling.

For example, a production log obtained in horizontal tight gas well is shown in Figure 11. The well was stimulated using the "perf-and-plug" approach over an approximate 4,000-ft interval. Integrated analysis of the flowmeter, temperature, resistivity, and gas hold-up data enabled quantitative interpretation of the profile: although seven of the nine perforation clusters exhibited flow, four of the perforation clusters appear to be contributing approximately 75% of the flow.

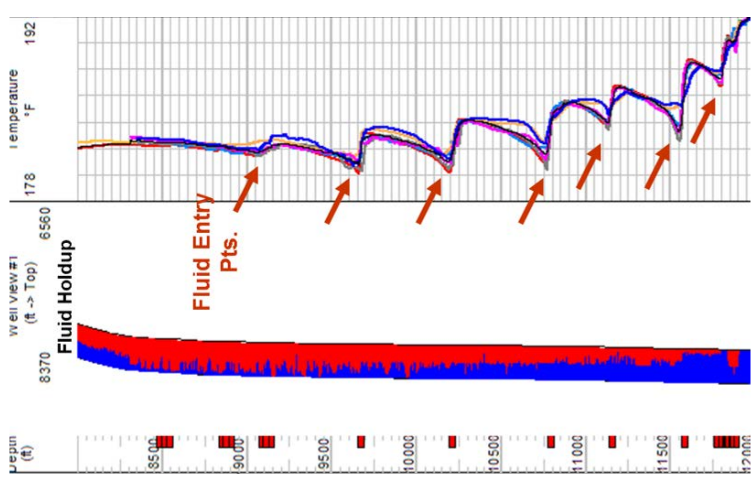


Figure 11. A production log obtained in a horizontal well stimulated using the perf-and-plug approach.

Improving Control of Treatment Placement: Novel Selective Stimulation Technologies

During the last decade, extensive research and development coupled to field experimentation has enabled development of several new technology solutions that provide more control of stimulation treatment placement, reduction in the surface footprint, and can be implemented at an equitable or even more competitive cost structure when tailored for the local conditions.

These technologies include:

1. Just-in-Time Perforating ("JITP") stimulation method[7]
2. Annular coiled-tubing fracturing ("ACT-Frac") stimulation method[8]
3. Simultaneous operations[9]

Conventional multi-zone stimulation approaches generally fall into one of two categories: (1) the placement of individual treatments via a single pumping event and the deployment of tools and equipment into a wellbore to facilitate selective isolation and tailored stimulation of each individual zone; or (2) multiple treatment stages are placed during a single stimulation pumping event using various flow control or fluid diversion approaches to coerce fluids into the targeted intervals. While approach (1) provides high-quality stimulations that maximize production from each reservoir interval, the approach is generally costly due to the time and equipment required for implementation.

As a result, cost control is generally achieved by stimulating only the highest quality reservoir intervals (bypassing smaller or less attractive intervals). Approach (2) minimizes the cost per stimulated interval by reducing the time that equipment is mobilized. However, the stimulation treatments placed using this approach are generally poorer in quality because treatment fluid delivery to each individual reservoir interval is not assured or directly controlled. More specifically, when multiple reservoir intervals are simultaneously exposed to a stimulation pumping event, some reservoir intervals may not be stimulated, thus reducing the total number of treated intervals. The remaining intervals may receive disproportionate volumes of treatment fluids that deviate appreciably from the optimized single interval treatment design. The end result is a larger number of intervals treated per unit stimulation cost but with generally poorer stimulation effectiveness.

To capture the optimized production benefits associated with approach (1), and the cost reduction benefits associated with approach (2), ExxonMobil has developed Multi-Zone Stimulation Technologies (referred to herein as MZST℠) which can improve the recovery and economics in unconventional reservoirs requiring multi-zone stimulation treatments. The technologies provide a toolkit approach to enable treatment optimization based both on reservoir conditions and considering local conditions such as in-country equipment and personnel resources. These technologies allow the stimulation of reservoir intervals that normally would be bypassed, thus increasing: 1) the production rate per well; and 2) the total hydrocarbon recovery.

Just-in-Time Perforating Stimulation Technology (JITP)

JITP involves pumping high flow rate treatments down the casing with a perforating gun assembly in the well to selectively perforate one interval at a time. Diversion between treated intervals is promoted through the deployment of ball sealers.[10] A well is stimulated using the JITP method by sequentially treating individual zones via the combination of selectively perforating single intervals and promoting the isolation of these intervals through the deployment of ball sealers. A single continuous pumping operation allows uninterrupted operations.

Figure 12 shows the JITP stimulation process. If zones have already been stimulated, the gun assembly is run with a bridge/frac plug and setting tool, and the plug is set below the first zone to be stimulated. After setting the plug, the gun assembly is positioned at the first zone and the first gun is fired. The gun assembly is then raised to the next zone of interest and the first treatment is pumped. At the tail-end of the treatment, ball sealers are added to the flow, with at least one ball sealer for each perforation. When the ball sealers arrive downhole and seal the perforations, as evidenced by a sharp rise in wellbore pressure, the next gun is fired and the second treatment is initiated without ever shutting down the pumps. This process is repeated for as many zones as there are individual guns on the deployed assembly. Once all the target zones have been stimulated, the gun assembly is retrieved. This process, or JITP event, is then repeated until the entire well has been completed.

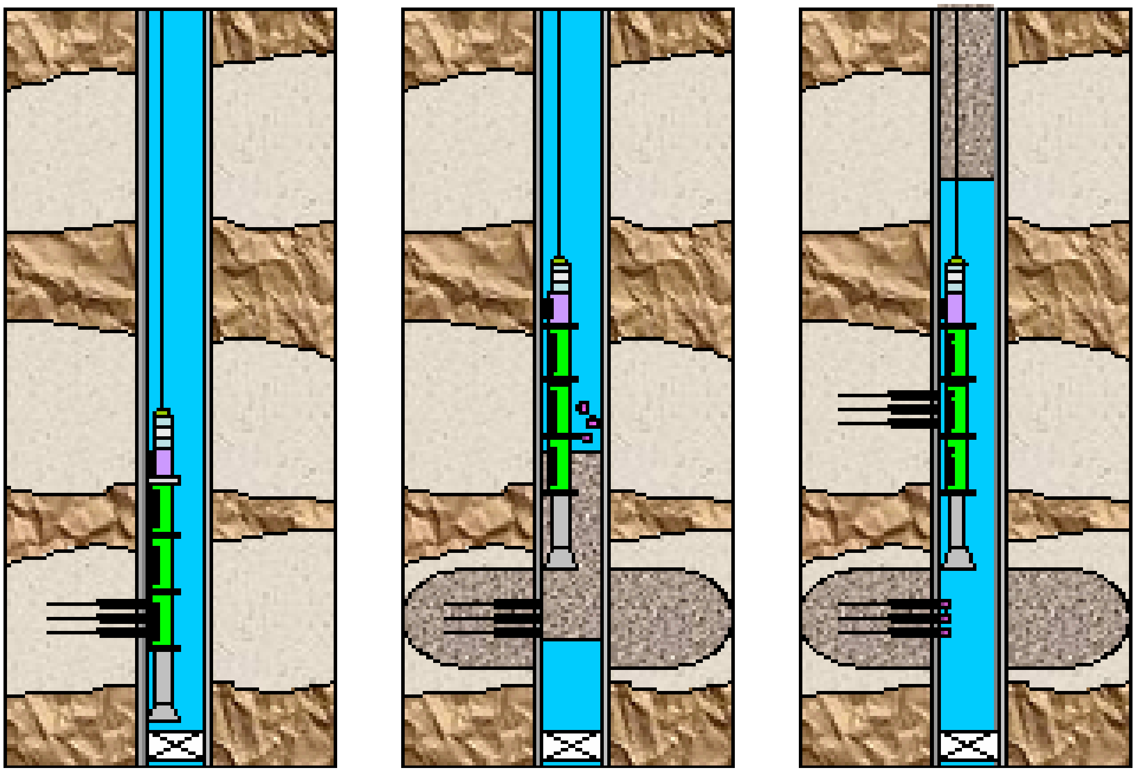


Figure 12. JITP stimulation process (shown for the case of a vertical well).

The JITP process relies on success in several key technical areas: 1) ball sealers must reliably flow past the BHA during pumping operations; 2) the BHA must not become differentially "stuck" to perforations while a treatment is being pumped; 3) balls must tightly seat against perforations to mitigate leakage and ball sealer erosion; 4) if a pumping operation is interrupted, balls should be capable of re-seating when pumping is re-initiated; 5) the perforating operation must be properly timed to ensure that the balls have passed the BHA before the next gun is fired; and 6) if the stimulation treatment fluids are staged (e.g., varying fluids and/or proppant concentration), then proper arrival of the ball sealers is important.

To date, more than 350 of vertical and S-turn wells having 4-1/2-inch or 5-1/2-inch production casing have been successfully stimulated with more than 7,400 treatments. Zones have been stimulated at depths of 14,700 ft MD, formation temperatures up to 320ºF, and maximum surface treating pressures up to 9,500 psi. In addition, during the last 2 years extensive work has been undertaken to deploy the JITP method in the horizontal wells, and the ability to reliably execute operations has been demonstrated in applications in the N. America Fayetteville shale. [11]

Annular Coiled Tubing Fracturing ("ACT-Frac") Stimulation Method

The annular coiled tubing fracturing (ACT-Frac) was developed with the objective of capturing further enhancements to stimulation treatment diversion. The ACT-Frac approach relies on the deployment of a bottomhole assembly ("BHA") that permits multiple treatments with a single BHA deployment into a well. Typically the BHA is conveyed via coiled tubing, isolation between treatments is achieved using a resettable packer, and perforation is most commonly performed by abrasive jetting (and use of select-fire perforating guns has also been demonstrated). The treatment is pumped down the tubing-casing annulus to achieve the high flow rates necessary for efficient and effective stimulation. Two typical types of ACT-Frac bottom-hole assemblies are shown in Figure 13.

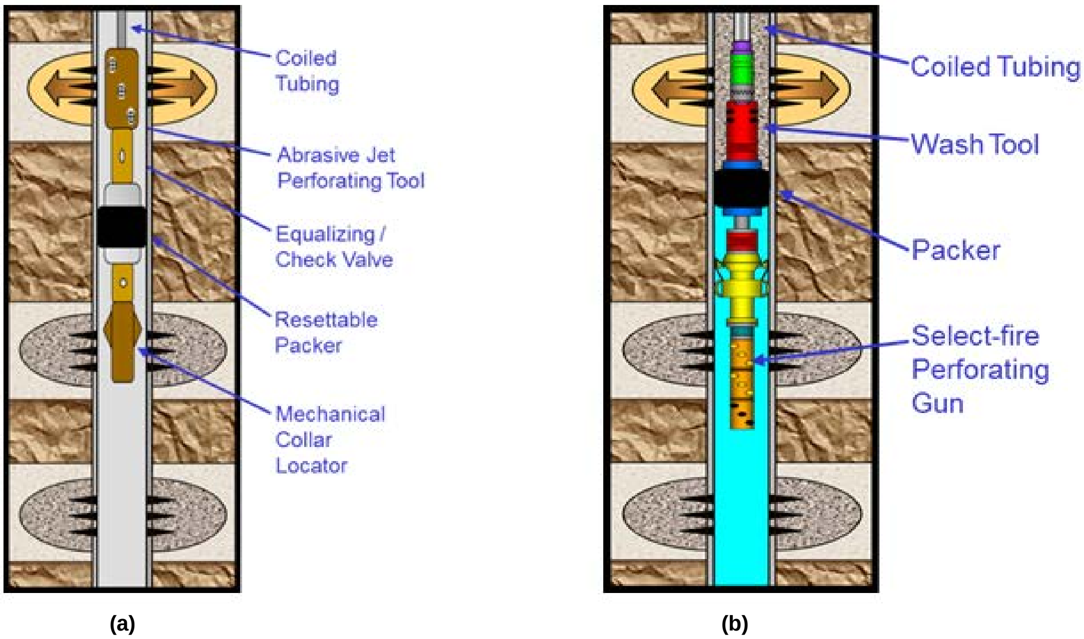


Figure 13. The ACT-Frac bottomhole assemblies, two types: (a) BHA with abrasive jet perforator, mechanical collar locator, and resettable packer; and (b) BHA with select-fire perforating guns and casing-collar locator controlled by electric line.

A well is stimulated using the ACT-Frac method by sequentially treating individual zones starting from the bottom (or toe) of a well and moving uphole (or towards the heel). Each zone is treated separately using a single pumping event without the use of bridge plugs or frac plugs. Positive isolation is achieved using multi-set downhole equipment that is moved uphole from zone-to-zone to facilitate multiple treatments via a single deployment of wellbore equipment into a well. The tool enables the ability to circulate and wash the wellbore if desired. This can be advantageous to quickly mitigate a screen-out of a proppant fracture treatment for example. Figure 14 illustrates a typical ACT-Frac stimulation process. The lowest ACT-Frac perforating gun is positioned adjacent to the first zone (using the CCL for depth control) and the perforating gun is fired. The BHA is lowered below the perforations and the slips and packer are set. The stimulation treatment is then pumped at high flow rates through the casing-tubing annulus. When the stimulation treatment is completed, pumping is terminated; the BHA is released and moved uphole to the next interval. When the second gun is positioned adjacent to the second zone the perforating gun is fired, the BHA is lowered below the perforations, and the process is repeated. A significant benefit is the well can be immediately produced up the casing, since plug drill-out is not required.

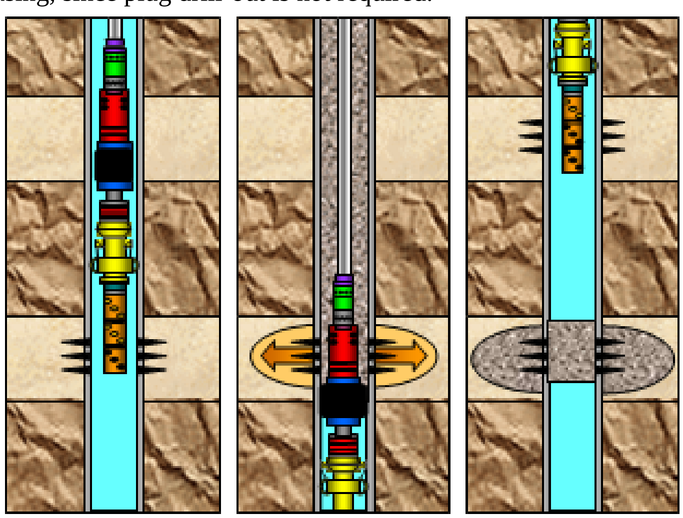


Figure 14. ACT-Frac stimulation process.

The packer diversion method provides "leak-tight" positive isolation between the interval being stimulated and the intervals previously stimulated; this allows a single pumping event to place a tailored interval-specific treatment while ensuring that previously placed stimulations are not damaged or altered by subsequent stimulation treatments. The technique is amenable to application in deviated and horizontal wellbores. This technique offers better control and reliability than alternative coiled tubing methods that rely on setting of sand plugs as the diversion method.

As of mid-2012, the ACT-Frac method using the abrasive jetting as the perforating device has been used in over 800 wells and over 10,700 treatment, including vertical and horizontal wells. This technique can be applied to many different types of unconventional reservoirs, including tight gas, tight oil, shale gas, and coal-bed methane. A unique benefit of the ACT-Frac method using the abrasive jetting perforating device is that this approach eliminates the use of explosives (e.g., conventional shaped charge perforating) and therefore can be an excellent system for stimulation in locations where it is preferred to avoid transport and use of explosives. The relatively short BHA assembly also makes this amenable for application in a wide variety of situations, as the lubricator can be much shorter than that associated with other stimulation methods. Finally, the packer provides a “leak-tight” seal and essentially perfect diversion; this provides significant advantage over “sand plug” coiled tubing approaches in horizontal well application, given problems with reliable placement and sealing of sand plugs in horizontal wells.

This method has been identified as providing significant performance uplift in multi-zone stimulation applications.[12] This technique may find the most beneficial utility for application in shallow wells or when smaller volume stimulation treatments may be required, and number of fractures per well is limited. These methods have enabled lower cost and better control of treatment placement in many applications, and with technology via licensed service providers, has been deployed in many types of reservoirs in the United States and other international locations.

Simultaneous Operations

Simultaneous operations “SimOps” technology[13] has enabled substantial benefits from operational efficiencies associated with multi-zone stimulation operations. Specifically, the technology enables sequential pumping operations on multiple wells without suspending fracturing operations waiting for non-pumping events (such as wireline rig up and running, setting frac plugs, etc.). In this manner, crews are more effectively utilized and the overall completions time greatly reduced. Of significant benefit is the reduced working footprint and reduced environmental impact from repeated equipment mob/demob operations.

As illustrated in Figure 15, simultaneous operations technology has been extensively deployed in Piceance Basin for stimulation of vertical wells on a multi-well pad, and can also be used for any resource requiring stimulation and development by multiple wells drilled from a single surface location, such as in Horn River Basin (Canada). Simultaneous operations has enabled highly efficient pumping operations to be performed with minimal downtime, as well as enabling a more effective range of options to respond to what would otherwise be “non-productive-time” events such as screen-outs or individual well equipment maintenance. SimOps can be deployed in combination with a range of stimulation methods, including JITP, ACT-Frac, limited-entry, perf-and-plug, and packer/sliding sleeve systems and methods.

(a) (b)

Figure 15. SimOps technology examples for (a) multiple vertical tight gas wells on a single pad location in Piceance Basin using JITP stimulation and (b) multiple horizontal shale gas wells in Horn River Basin stimulated with the conventional “perf-and-plug” method.

The major components in the simultaneous operations are a stimulation fluid storage system, a stimulation fluid pumping system, a manifold system to enable stimulation fluids to be directed to any of the wells on the pad, flowline manifolds, two cranes, two wireline units, perforating tools, and a coiled tubing unit. Multiple wellheads are connected together from the high pressure pumps through a single manifold. By configuring the valves prior to pumping fluids and proppant, the stimulation operator can choose which well will be treated and avoid the potential hazards and time delays associated with rig up and rig down of high pressure lines multiple times over the course of many days. Individual choke manifolds are installed on each well to accommodate flow back and recovery of fluids used to transport the proppant through the well bore.

Autonomous Methods for Optimizing Multi-Zone Stimulation Operations

Given the significant performance improvements that have been enabled by JITP, ACT-Frac, and SimOps, the next step change technology for operational enhancement of selective stimulation is now being pursued with development of "autonomous delivery systems" where the focus is on the complete removal of the downhole tool conveyance methods; specifically, elimination of the need to use wireline, coiled tubing, or jointed pipe as part of the multi-zone stimulation method.[14]

Elimination of the wireline or tubing can offer further significant operational enhancements as the overall surface footprint can be reduced with elimination of large cranes, wireline units, and/or coiled tubing units since these are no longer necessary for deployment and/or control of the downhole selective stimulation tools.

An autonomous perforating tool (Figure 16) is being developed which entails a self-destructing disposable perforating tool run in a well without a wireline. The design and construction provides for a hermetically sealed unit, with all components, perforating charges, batteries, logging devices, etc. integrated within the device and sealed from exposure to wellbore fluids. To achieve the functionality, the perforating tool will contain essentially "frangible" components that will destruct into small pieces upon perforation.

Specifically, the frangible devices include: 1) a logging device; 2) an on-board navigation system; and 3) friable perforating guns. The on-board navigation system reads the log signals and performs real-time processing of the depth data. Upon matching of the desired depth, the system issues a firing command to the friable perforating gun assembly. The latter simultaneously initiates the self-destruction of the tool. Thus, the tool is completely destroyed after perforating and the remaining debris fall to the bottom of the hole, where they could be left, flowed back to surface or removed during cleanup prior to tubing installation. The volume of debris is small and does not require drilling additional rat hole.

Figure 16. Proof of concept design showing frangible components associated with an autonomous perforating device.

The delivery of the tool is achieved by either gravity free-falling in low-angle wells or by pumping it downhole during hydraulic fracturing or any other pumping operation in high-angle or horizontal wells. This tool, when coupled with the JITP process can further increase the efficiency of the multi-zone fracturing process by completely eliminating the need to stop and run wireline in and out of the well. A separate frangible perforating gun will be launched for each zone that will be hydraulically stimulated. For the case of JITP, zonal isolation will still be achieved by launching ball sealers either with the gun or ahead of the gun.

All components of the perforating gun technology have been successfully developed and tested. The system was also tested in three different test wells and performed as designed. Current work is focused on refining the design of the tool and expanding the range of possible applications of the technology to other areas, including autonomous delivery of chemicals or tools downhole.

Summary

Novel multi-zone stimulation technologies have enabled the development of "tight" resources that previously could not be developed economically and enabled the ability to optimize production resources distributed over thick gross intervals. These technologies are expected to become more broadly used methods-of-choice for numerous applications worldwide due to their ability to: 1) rapidly place numerous stimulation treatments tailored to the specific needs of each zone; 2) pump each treatment efficiently and effectively; and 3) make more efficient use of equipment, people, and surface site development. The value of “physics-based” design methods, measurement and diagnostic systems, and cross-disciplinary approach have enabled significant step changes in delivering more effective stimulations to a wide range of globally distributed “tight” resources.

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