Rapid Completions LLC Response

Baker Hughes Proceedings

IPR2016-00596 (U.S. Pat. No. 7,134,505)

IPR2016-00597 (U.S. Pat. No. 7,543,634)

IPR2016-00598 (U.S. Pat. No. 7,861,774)

Unless otherwise noted, all citations herein are to the exhibit list for IPR2016-01506 (774 patent). This exhibit list is available in the Patent Owner Response, Paper 51.

All page citations are to the page numbers added for these proceedings, not the native page numbers of the article, document, etc.

Frequently Cited Exhibits

2050 - McGowen First Declaration
2081 - McGowen Supplemental Declaration
2017 - A. Daneshy First Deposition
2085 - A. Daneshy Second Deposition

Thomson

Q. And just to be clear, Thomson does not disclose pumping fracturing fluid into an open-hole annular segment, right?

A. The paper does not describe that, no. The paper describes through a cemented casing in this case.

Ex. 2085, A. Daneshy Depo. at 54:10-14

Q. Was one of the goals of Ellsworth to create multiple fractures through open-hole annular segments?

A. It was not their main goal, no.

Q. Did they do that?

A. No, they didn't need to do that. That's why they didn't do it.

Ex. 2085, A. Daneshy Depo. at 78:22-79:2

Q. Does the Ellsworth reference describe hydraulic fracturing?

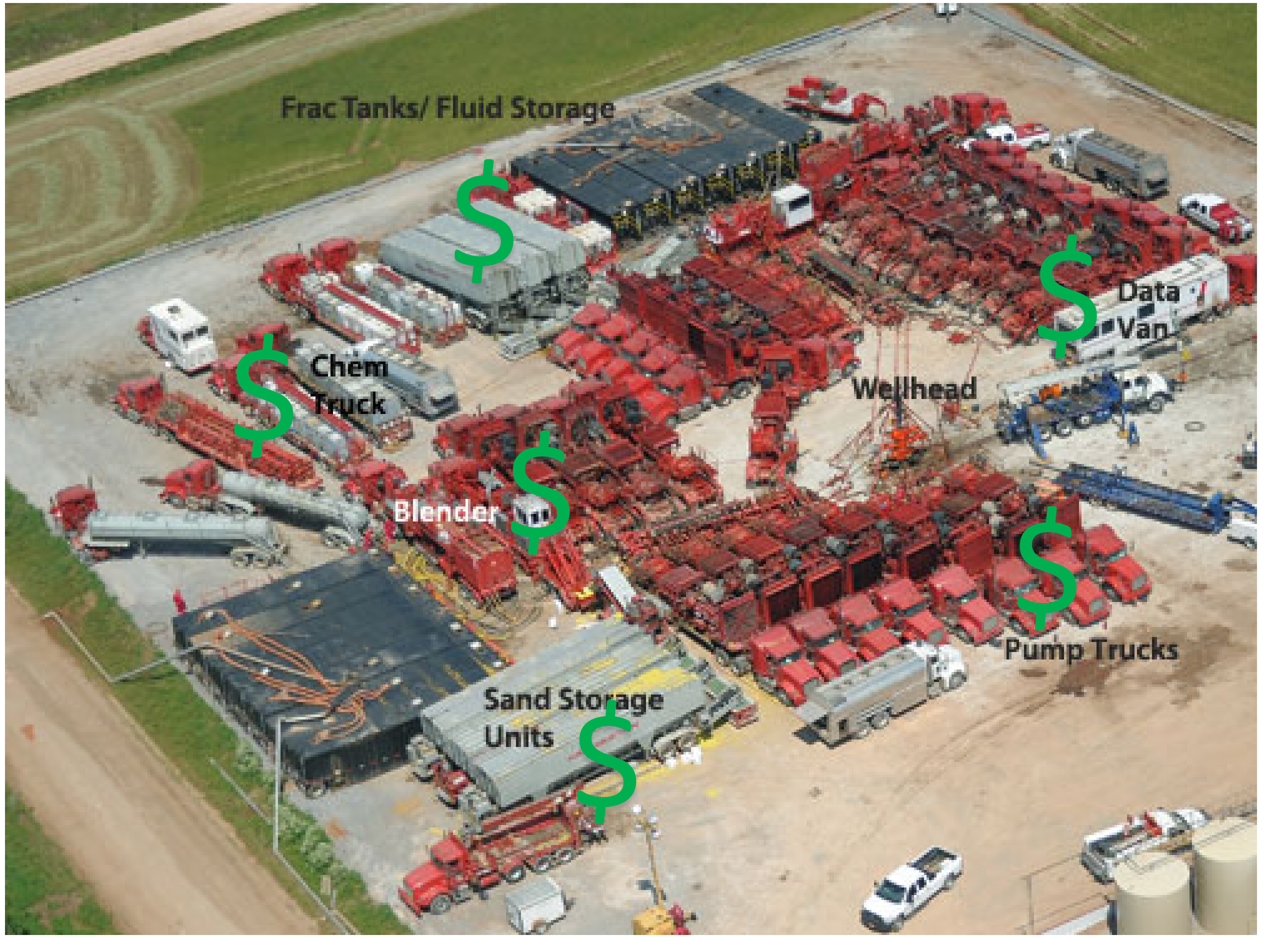
A. It describes acid stimulation, and it doesn't get into what pressures were used. So it’s not easy to discern whether the acid fractured the rock or not.

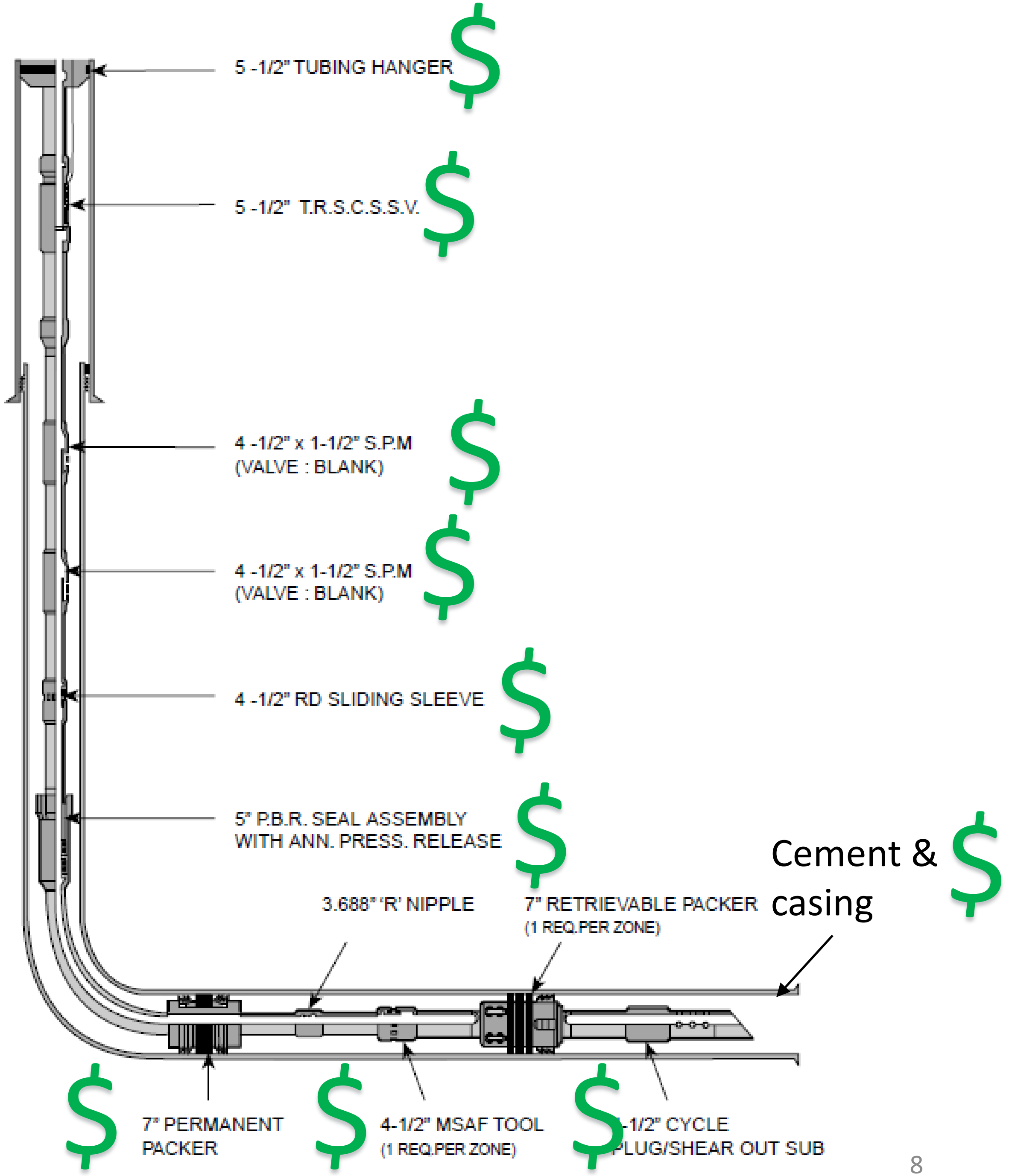
Ex. 2044, V. Rao Depo. at 66:17-67:6

Petitioners must prove a motivation to remove a component.

Pozen Inc. v. Par Pharm., Inc., 696 F.3d 1151, 1163 (Fed. Cir. 2012)

Amkor Tech., Inc. v. Int'l Trade Comm'n, 692 F.3d 1250, 1260 (Fed. Cir. 2012)

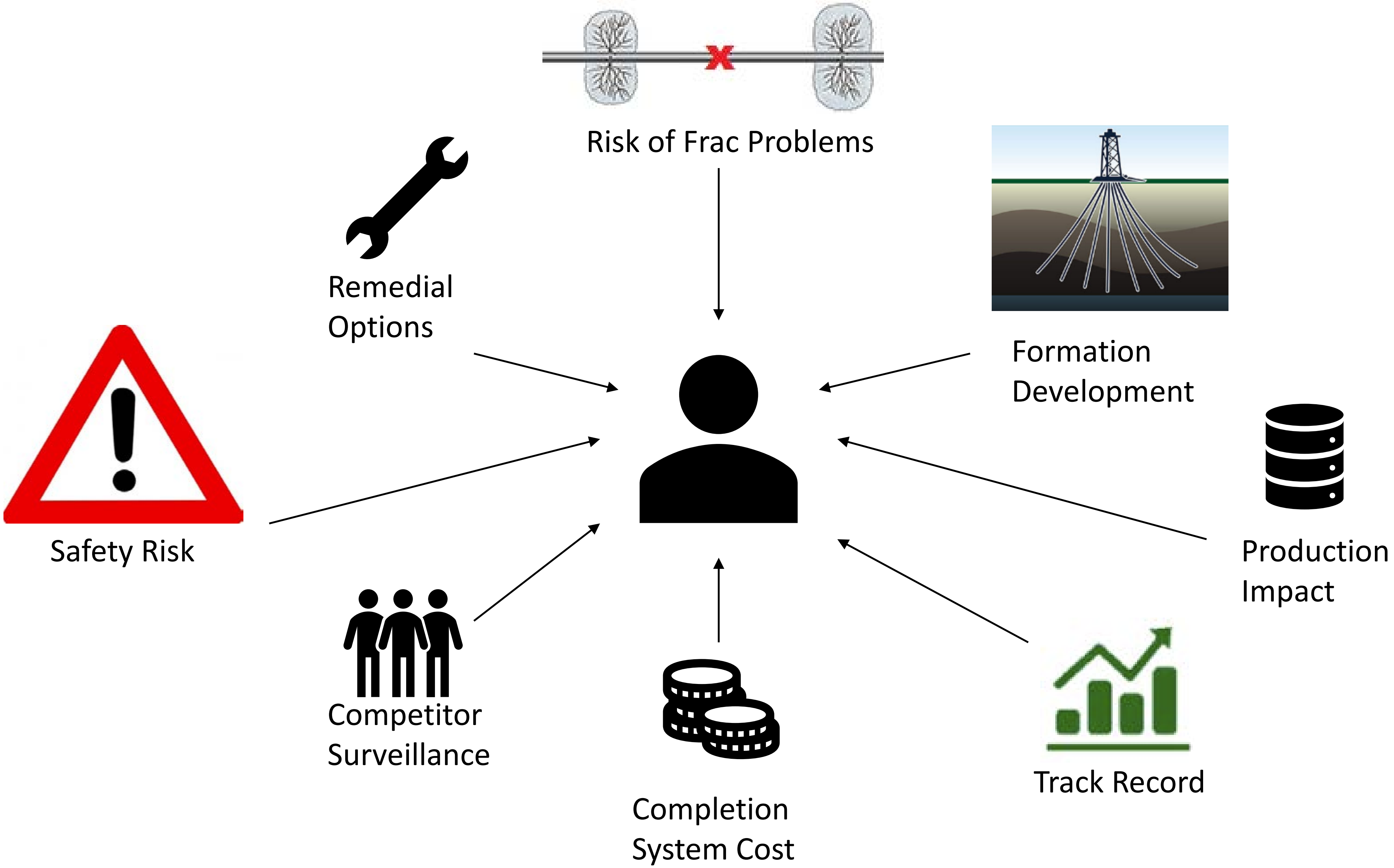

Frac Tanks/ Fluid Storage
Data Van
Chem Truck
Wellhead
Blender
Pump Trucks
Sand Storage Units


5 -1/2" TUBING HANGER
5 -1/2" T.R.S.C.S.S.V.
4 -1/2" x 1-1/2" S.P.M (VALVE : BLANK)
4 -1/2" x 1-1/2" S.P.M (VALVE : BLANK)
4 -1/2" RD SLIDING SLEEVE
5" P.B.R. SEAL ASSEMBLY WITH ANN. PRESS. RELEASE
3.688" 'R' NIPPLE
7" RETRIEVABLE PACKER (1 REQ.PER ZONE)
Cement & casing
7" PERMANENT PACKER
4-1/2" MSAF TOOL (1 REQ.PER ZONE)
4-1/2" CYCLE PLUG/SHEAR OUT SUB

Q. Does the Thompson reference explain why the authors use cemented casing in the horizontal portion of the well?

A. They don't go into it. As far as I can understand, **the prior wells in that platform had used casing and cementing and so -- and they were asked to improve the efficiency of the prior wells, so they continued to use what was being used.** I doubt it was a decision point.

Ex. 2044, V. Rao Depo. at 65:11-19


Risk of Frac Problems
Remedial Options
Formation Development
Safety Risk
Production Impact
Competitor Surveillance
Completion System Cost
Track Record

Harold McGowen - Fracturing Experience

- President and CEO, Navidad Resources LLC
- Overseen over 200 wellsites for NRL
- Voted best CEO for a medium size producer (TIPRO)
- Performed multi-year fracturing fluid performance study on 1,000 Codell-Niobrara refracs.
- Performed reserves projections and economic evaluation of 250+ Bossier/Cotton Valley wells in the Bossier trend.

Ex. 2050 at 54

Dr. Ali Daneshy – Fracturing Experience

- Director of Petroleum Engineering at University of Houston
- VP of Integrated Technology Products at Halliburton
- SPE Distinguished Lecturer
- Academic papers related to fracturing

Q. Did you write your report?

A. Did I write it personally? No.

[. . .]

Q. When you say reports, and I may have said reports, but we're talking about your declarations, right?

A. Yeah, exactly.

Ex. 2017, A. Daneshy Depo. at 123:24-25, 124:17-20

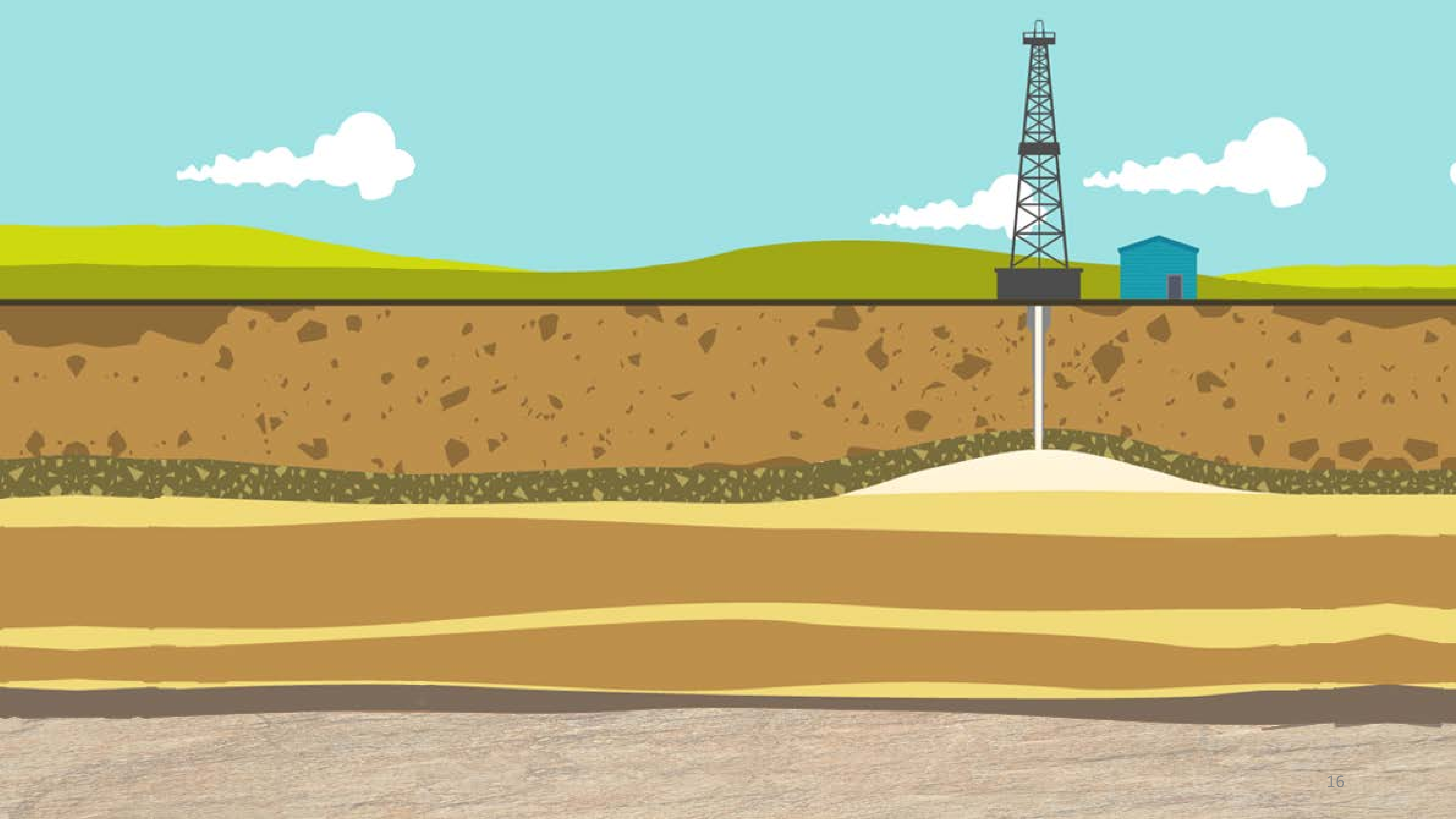
Q. Well, let me just ask you this. What's your understanding of the legal test for proving that a patent claim is obvious?

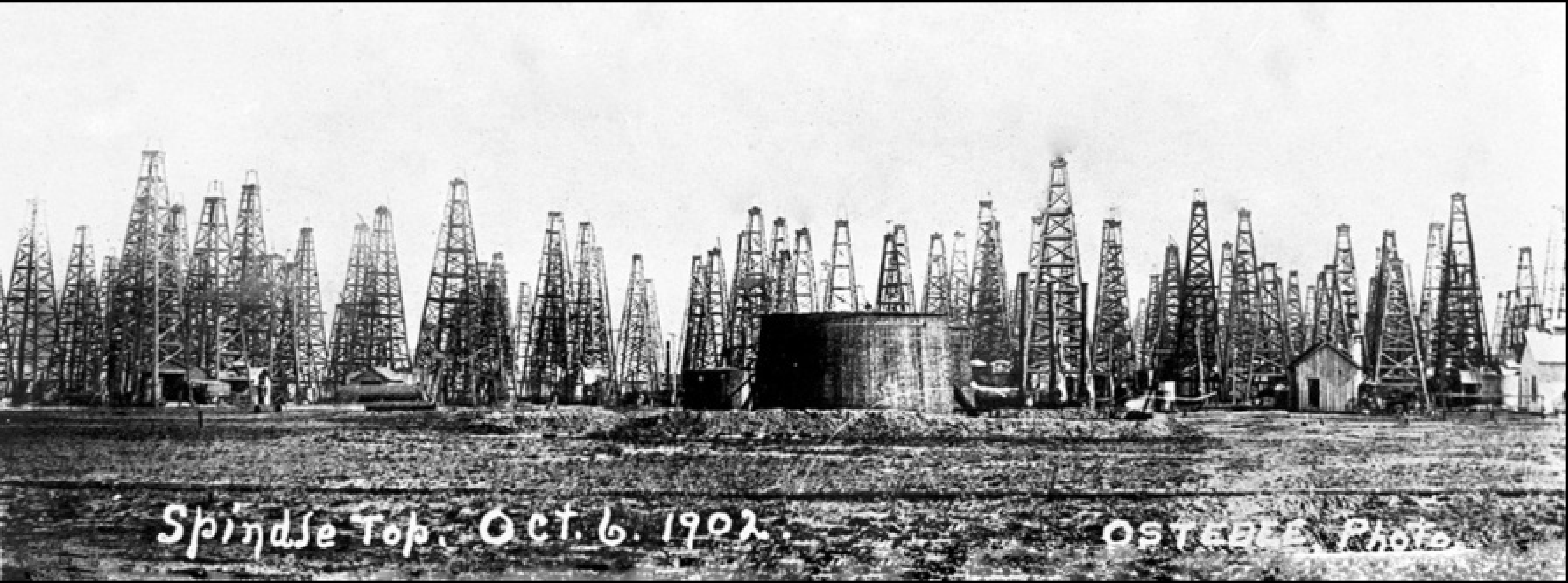
A. You're asking the wrong person. I think the definition is somebody -- a person of ordinary skill would be able to use the -- a person of ordinary skill would arrive at that, would come to the conclusion, I think. I don't want to give you -- because I know this is something that is -- I've worked with patent lawyers and this is one of those subjects that every time you get into it, each patent lawyer describes it different than others. But if a person of ordinary skill would arrive that it can be done. **Based on existing available information, existing knowledge, they would say it could be done.**

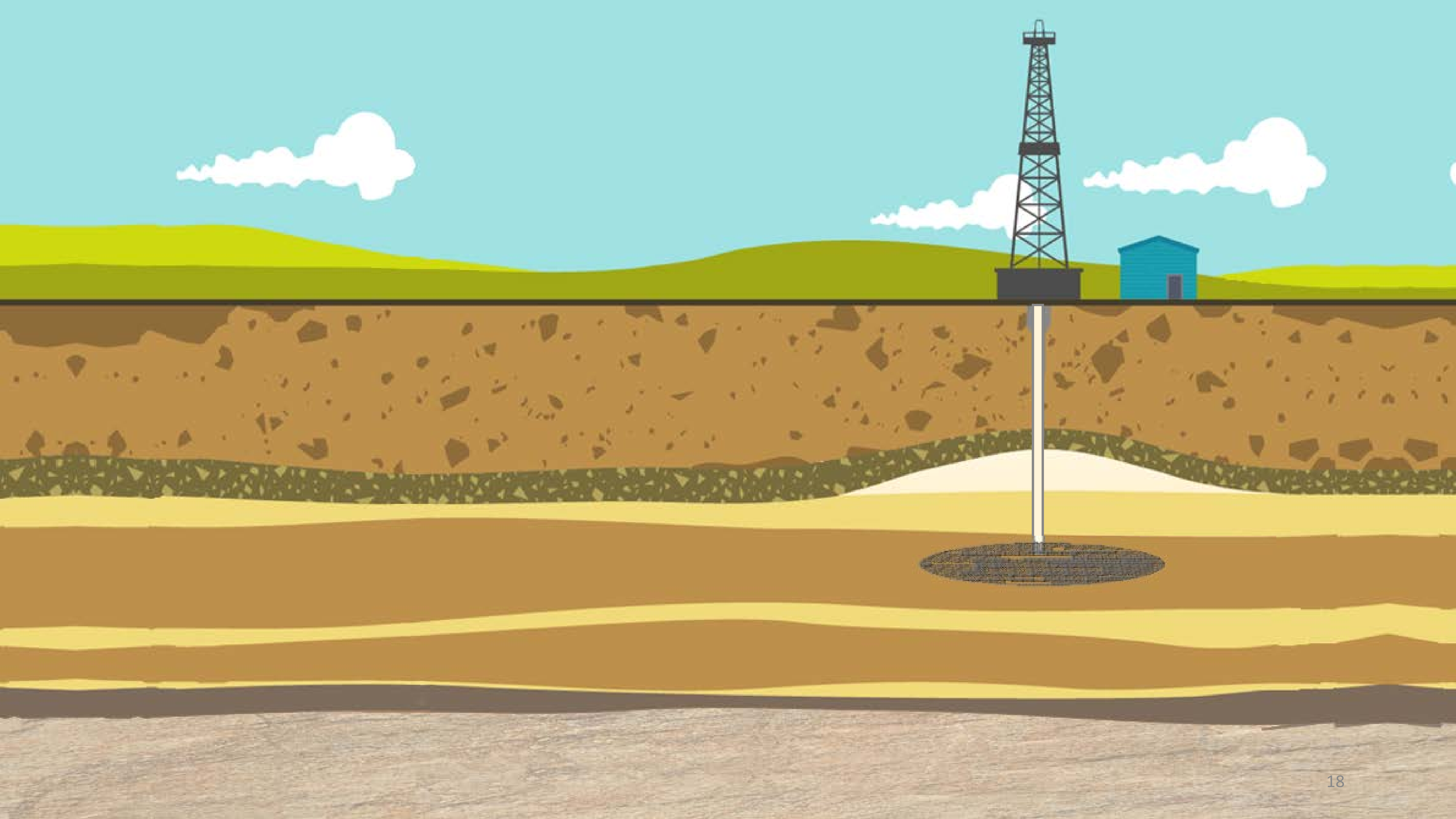
Ex. 2017, A. Daneshy Depo. at 123:24-25, 124:17-20

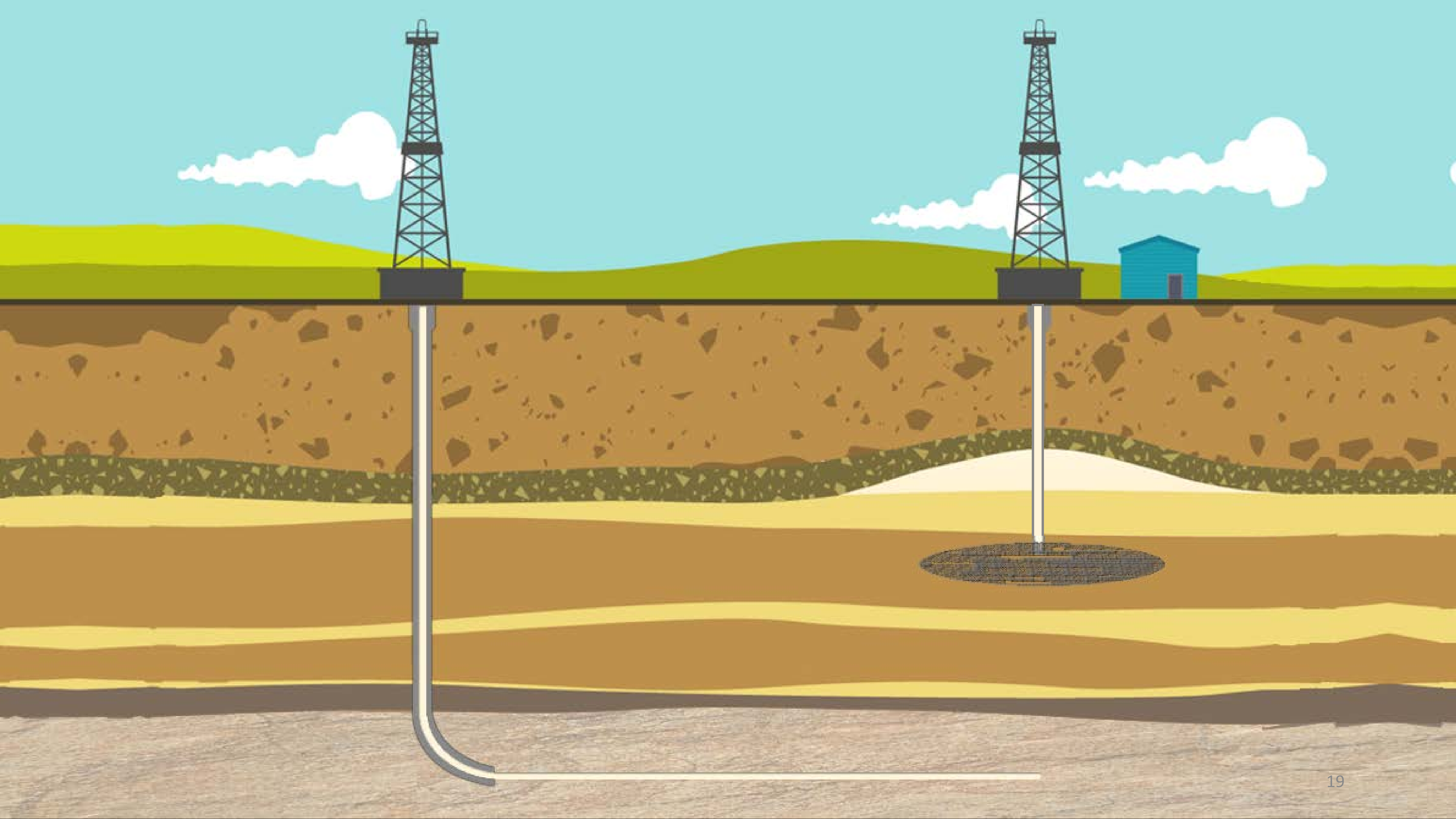
In the very first declaration that Dr. Daneshy gave, he did not render a conclusion on the legal issue of obviousness with respect to Thomson and its use in an open-hole in combination with the Ellsworth reference.

Ex. 2085 at 39:22-40:1 (Petitioners' counsel)




Spindle Top. Oct. 6. 1902.
Photo





SPE 164009

Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics.

Alberto Casero, Hammed Adefashe, Kevin Phelan, BP America Inc.

This paper was prepared for presentation at the SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28–30 January 2013.

Abstract

During the past decade, the combination of hydraulic fracturing and horizontal wells, has proven to be the key, to the unlocking of unconventional plays across North America and elsewhere. This efficiency has been accomplished by using two very distinct completion approaches: the Plug and Perf. method and the Open Hole Multi Stage (OHMS) completion system (typically ball activated fracturing ports).

The OHMS completion system has in general been applied to carefully selected fields and has not yet gained wider acceptance, across the industry, as a viable alternative to the more popular and extensively utilised Plug and Perf approach. This resistance to change and the reluctance to consider alternative completion approaches, are due to a number of factors, many of which reflect an operational comfort zone from which there is a hesitancy to stray. Often the disadvantages of the OHMS approach may be overemphasized, while the associated advantages are not suitably considered and vice versa for the Plug and Perf approach.

Case histories from a number of North American unconventional plays, for example the Red Oak, the Cotton Valley and the Granite Wash, will be both presented and analyzed. This analysis will focus on a number of aspects, including the hydraulic fracturing treatments, the operational efficiencies, the cost effectiveness and the overall risk reduction aspects of the OHMS vs. the Plug and Perf approaches.

Introduction

Over the past decade, the Oil and Gas industry has considerably increased the well completion activity levels taking place across the unconventional plays within North America. Continued advancements in both the completions technologies and the operational techniques, particularly when combining horizontal drilling and hydraulic fracturing, have allowed an efficient access to previously uneconomic resources to be achieved. These previously uneconomic resources comprise of a number of different plays, consisting of various pore fluids, formation lithologies and hydrocarbon trapping mechanisms. In this respect, the tight gas-sands, coal bed methane (CBM), shale gas and more recently shale oil opportunities can all be considered a part of the unconventional resource grouping.

Fundamentally, the reasoning behind the consideration of horizontal well drilling is fairly simple, horizontal wells will provide an additional amount of contact area within the reservoir and by this means an improved production rate compared to a vertical well can be achieved. However, the reality is not as straightforward and the increased surface area, exposed to the reservoir, is not the only factor directly affecting this enhanced production rate.

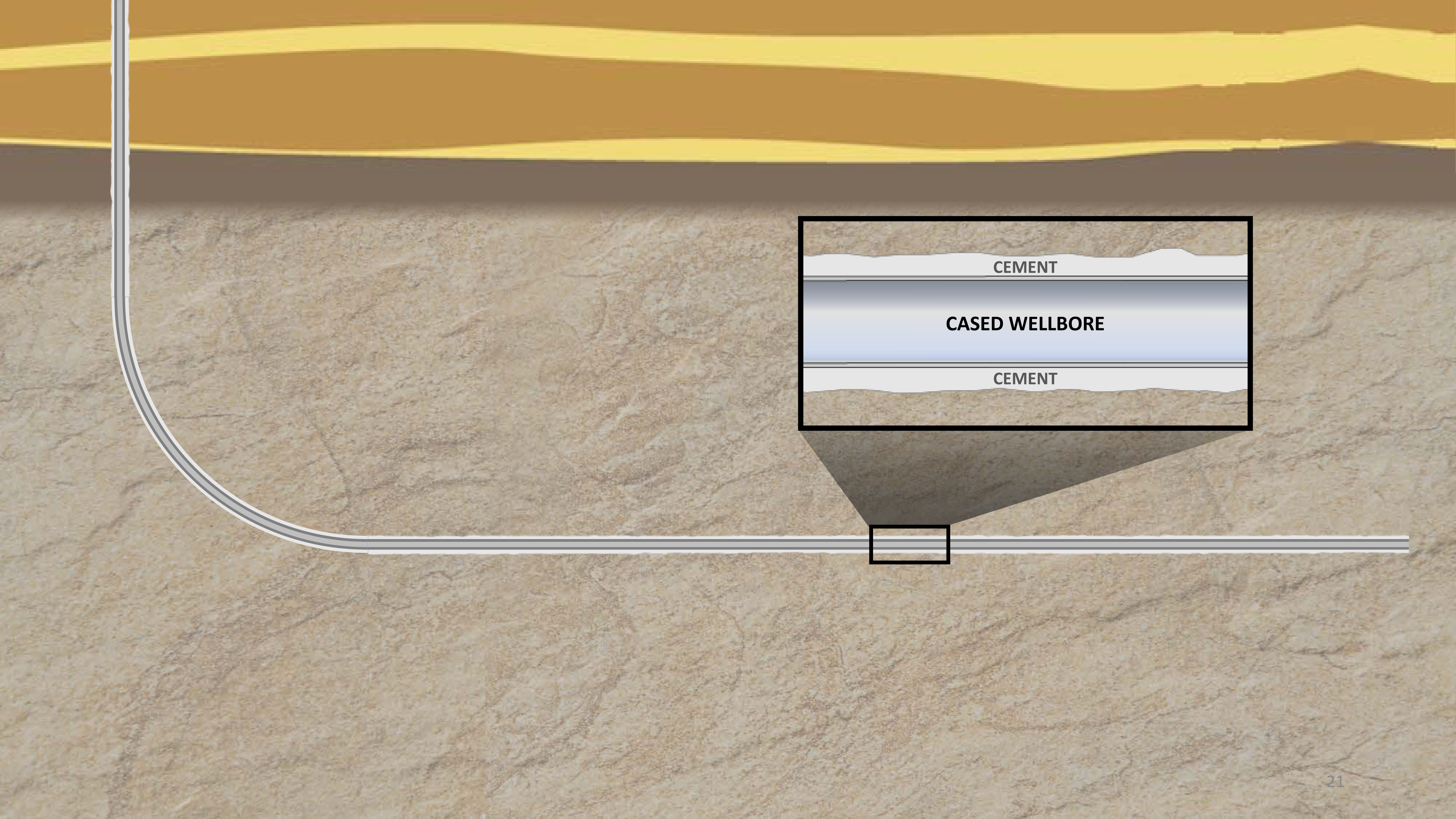
In order to explain more clearly, consider the simple derivation of the Darcy flow equation for an ideal liquid, for a vertical well (1), written in oilfield units. This equation simply states that the production rate (q) is directly proportional to the applied drawdown (Δp), the reservoir thickness (h), the formation permeability (k), the wellbore radius (r_w) and is also inversely proportional to the pore-fluid viscosity (μ) and the fluid formation volume factor (B).

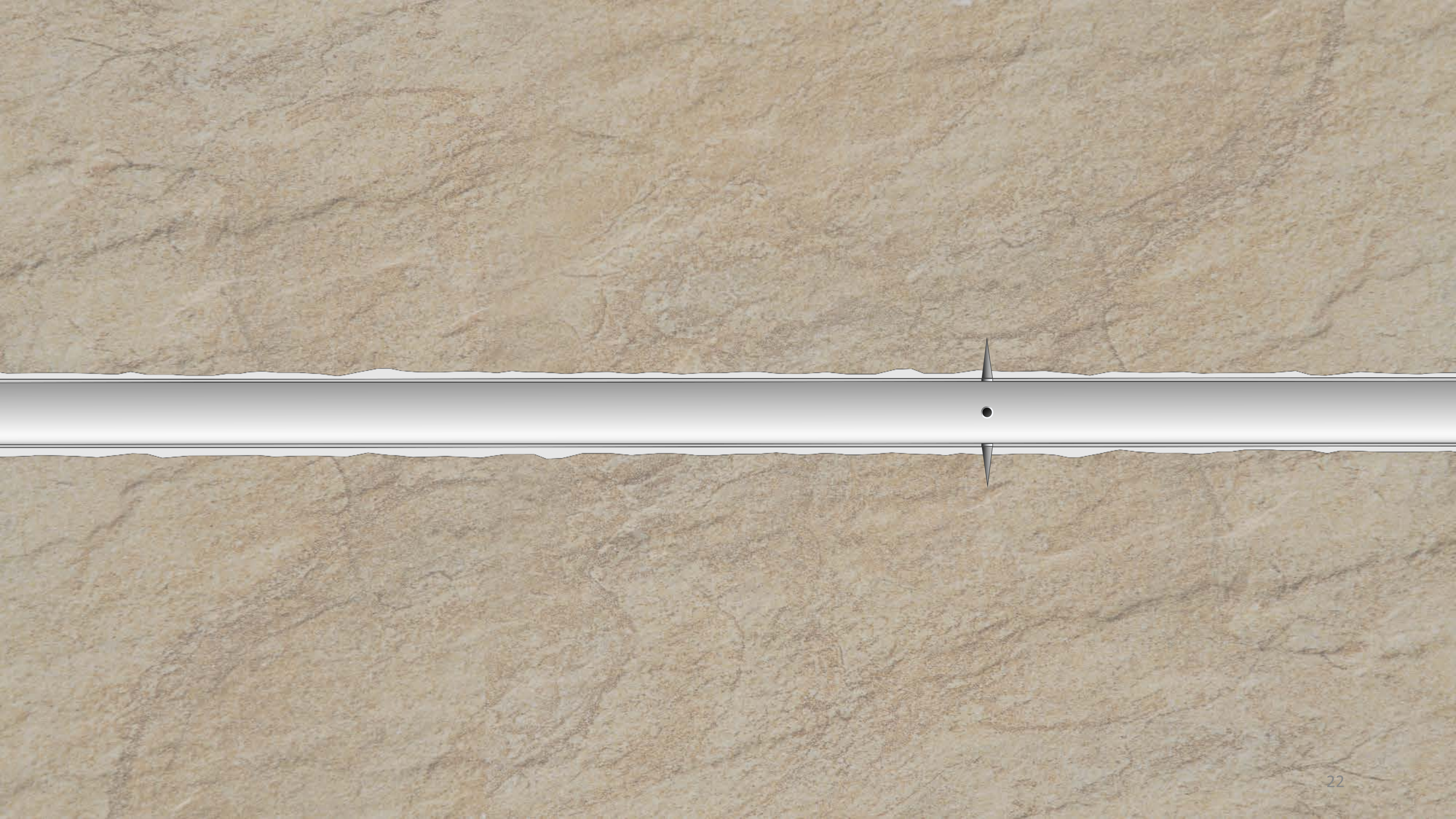
$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \qquad \ldots (1)$$

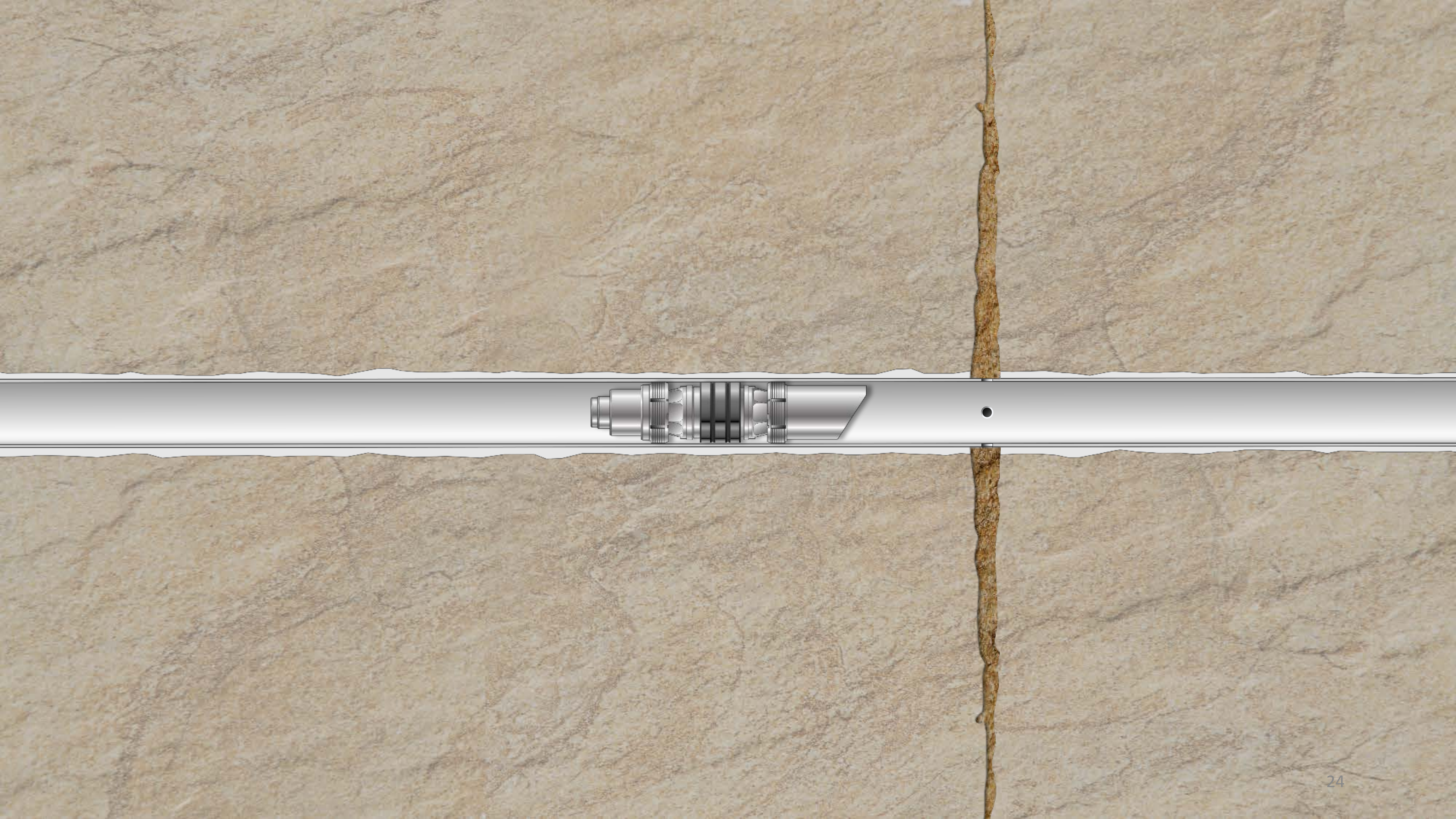
Exhibit 2001
IPR2016-00598

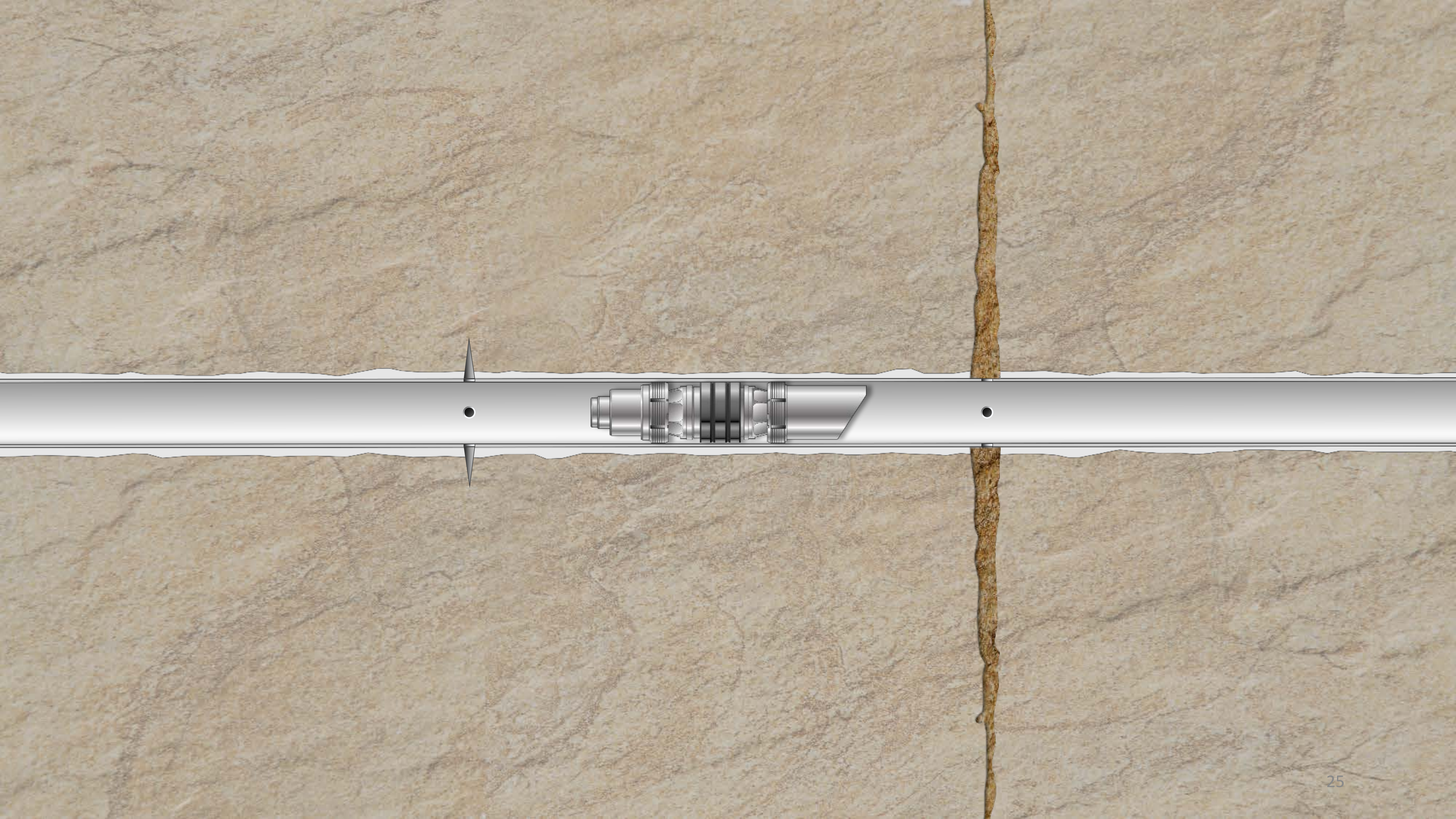
The P&P approach was the initial lower completion methodology that allowed the effective deployment of multi-fracture treatments in horizontal wells . . .

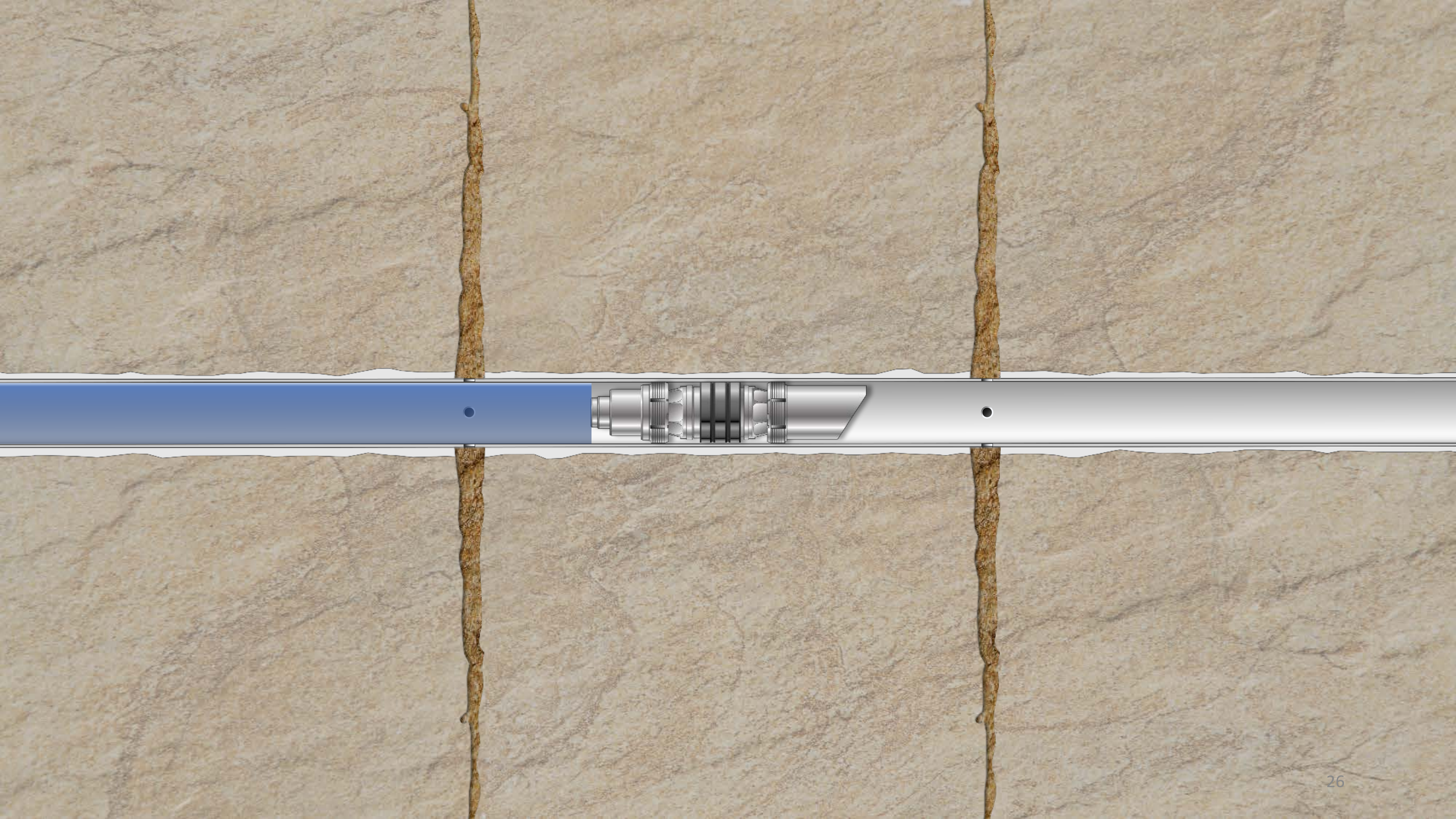
Ex. 2001 at 5, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013); see also Ex. 2050, McGowen Decl. at 26; Paper 51, POR at 13-15.

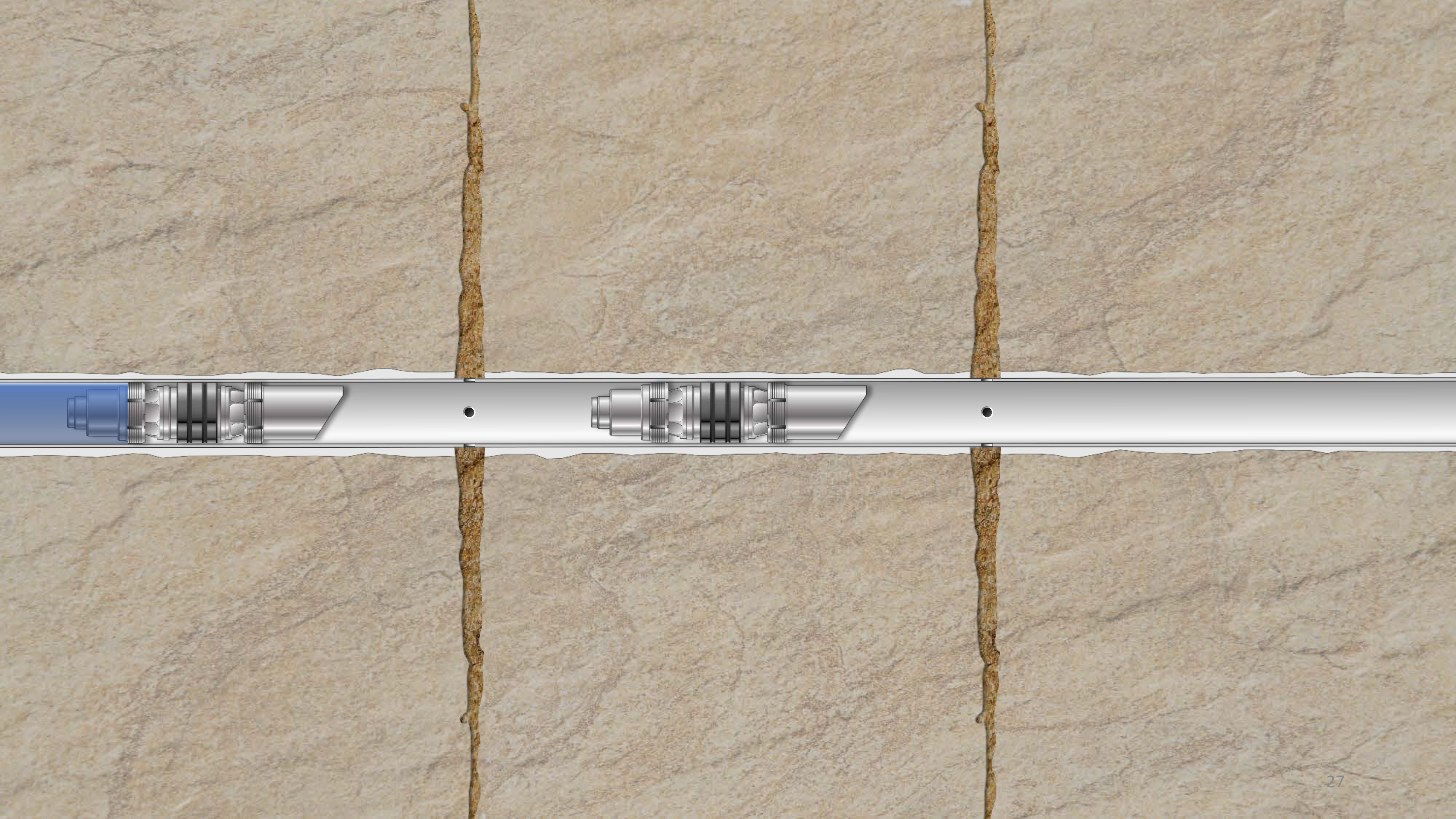

CEMENT
CASED WELLBORE
CEMENT

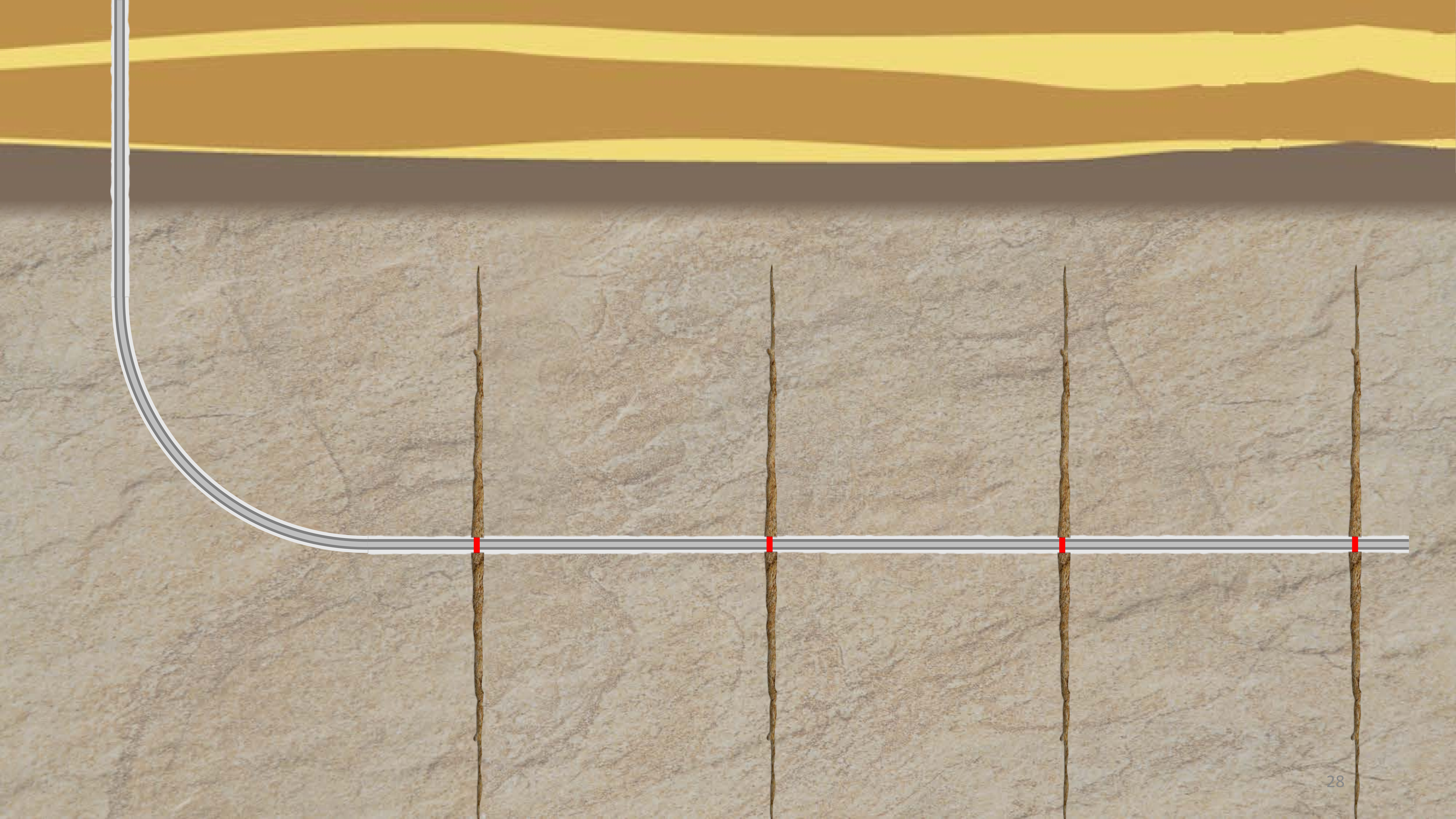


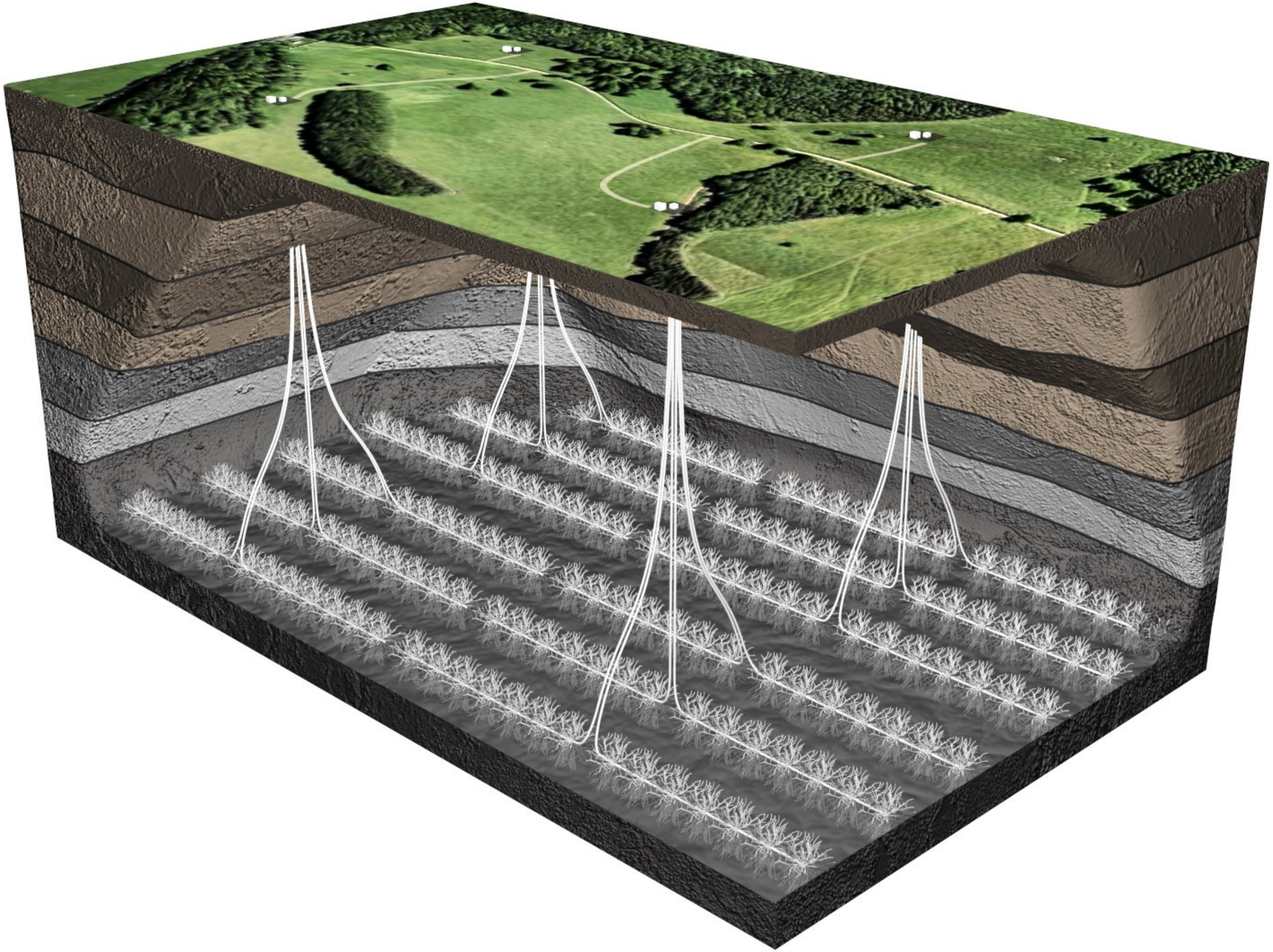










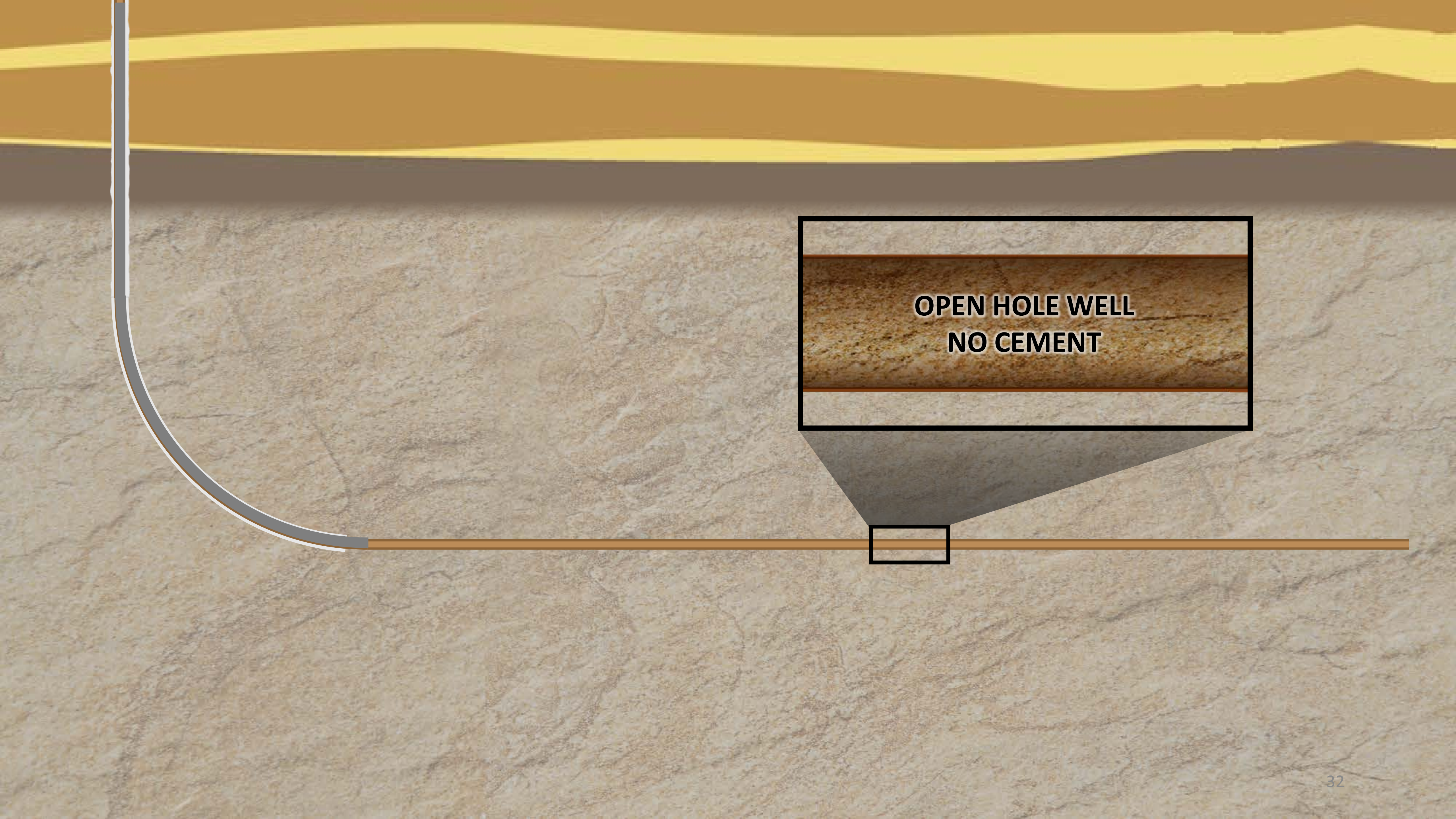


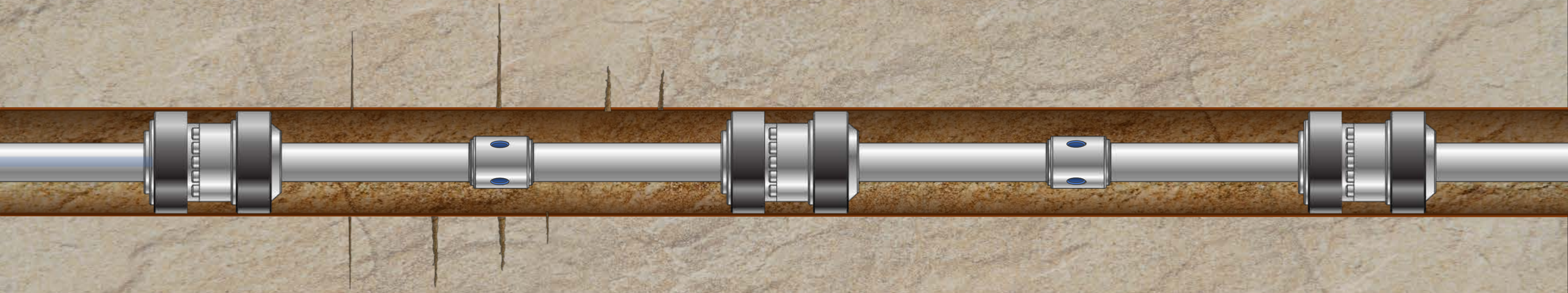
Q. Why does that difference matter?

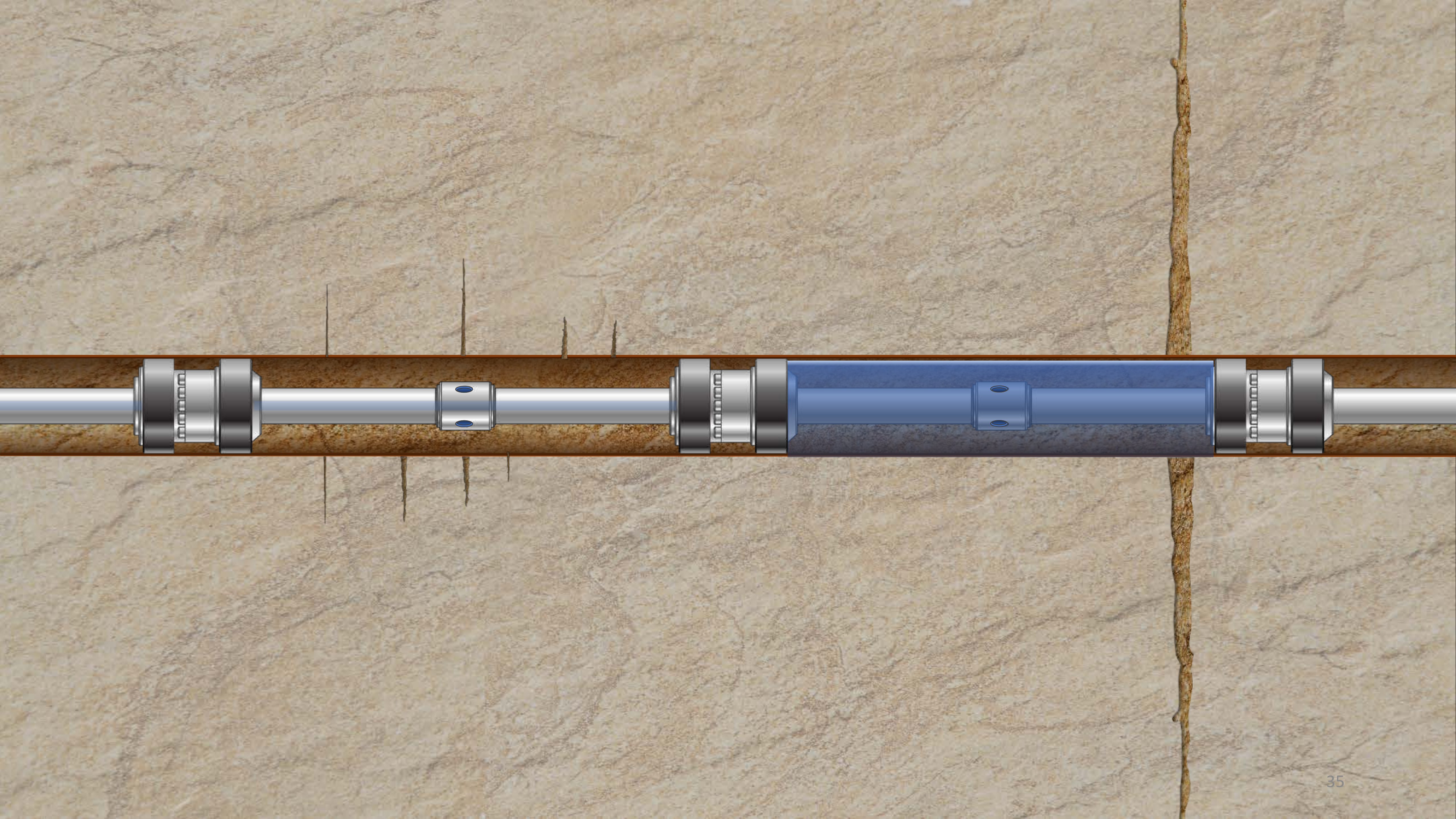
MR. GARRETT: Objection, form.

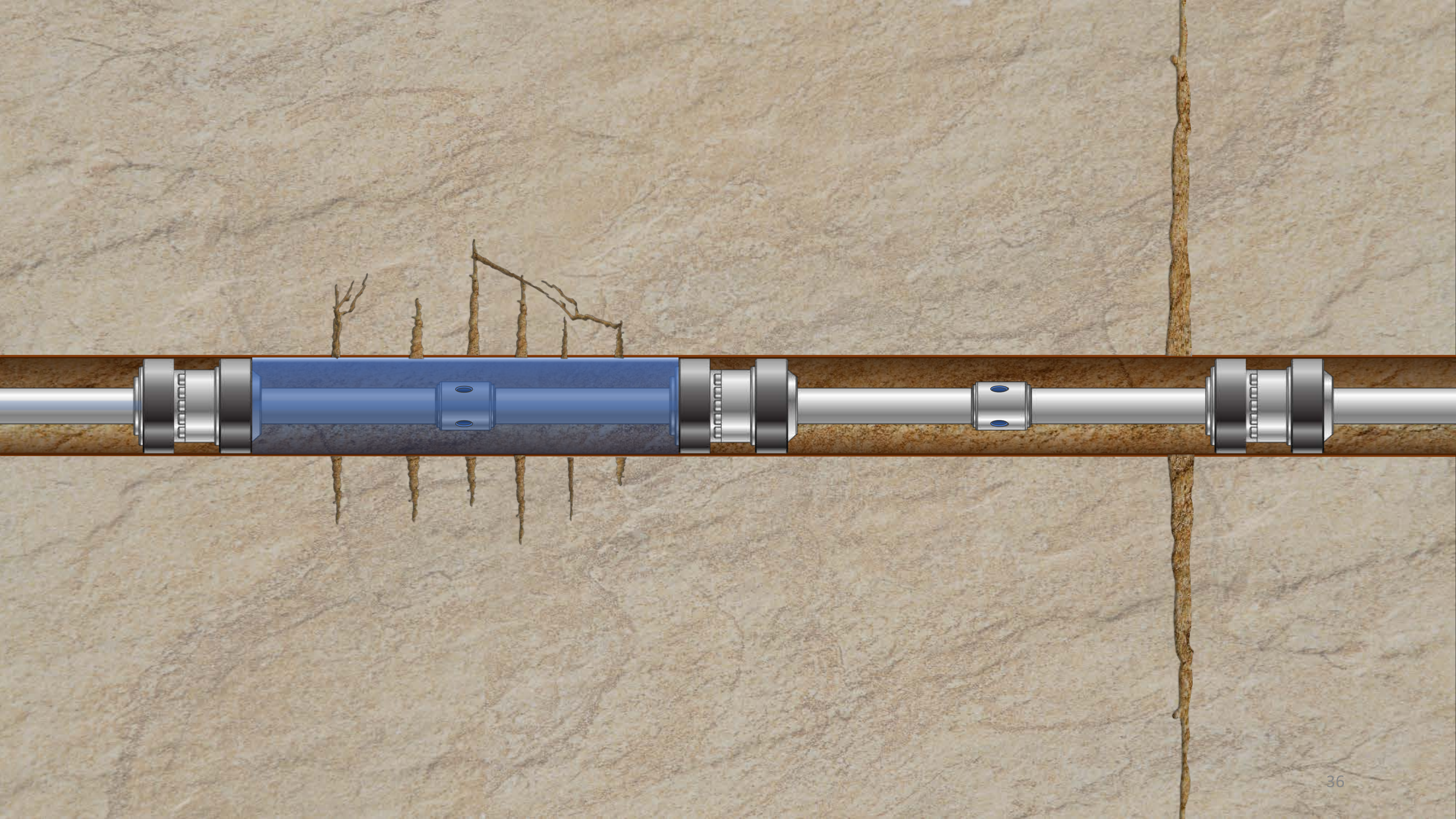
A. Because the location of the fracture influences [well] productivity and how the reservoir is being depleted. **You want uniform depletion of reservoir fluid so that you get as much of the oil or gas out of the formation; and so for that, it is better to know more accurately where the fractures are located.**

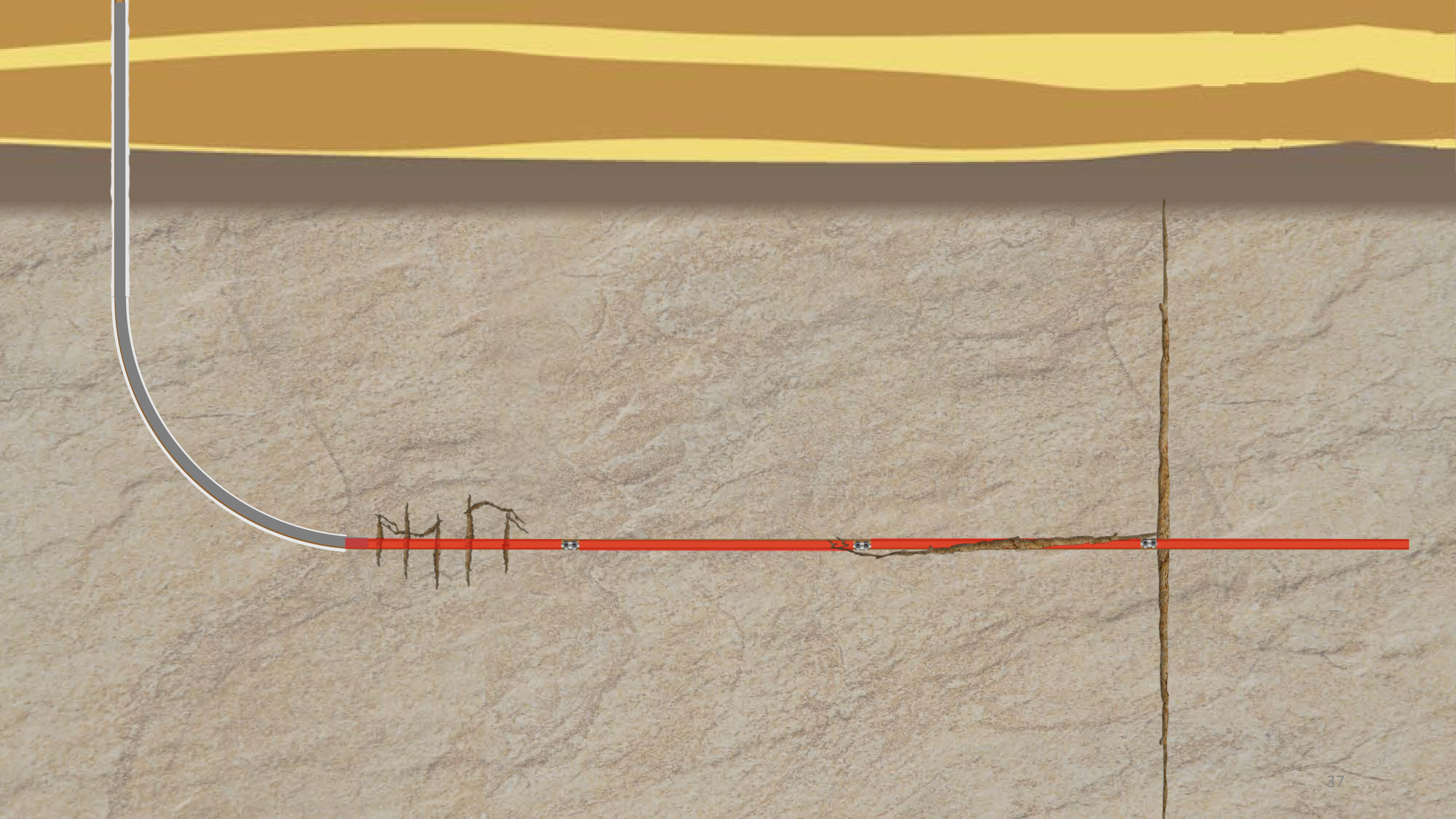
Ex. 2017, A. Daneshy Depo. at 21:13-20
Ex. 2050, McGowen Decl. at 28
Paper 51, POR at 14

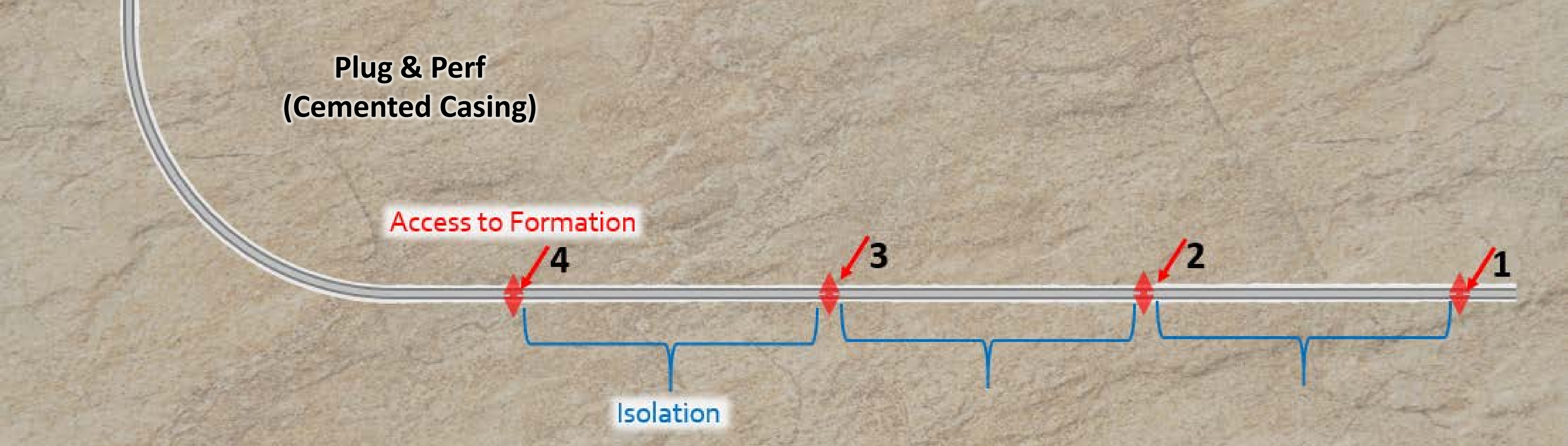

OPEN HOLE WELL
NO CEMENT

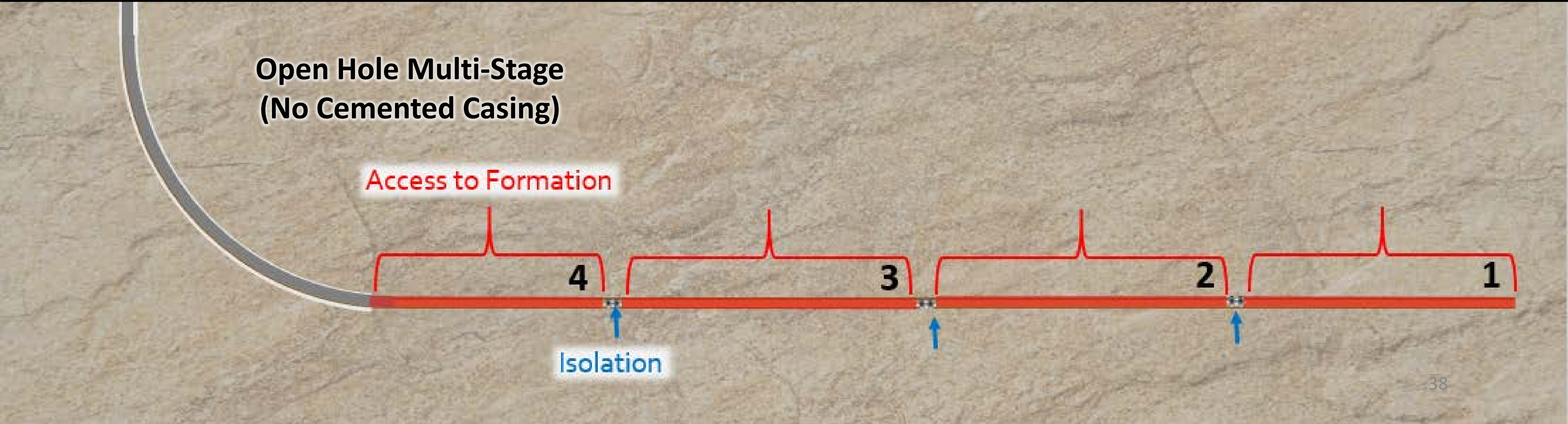


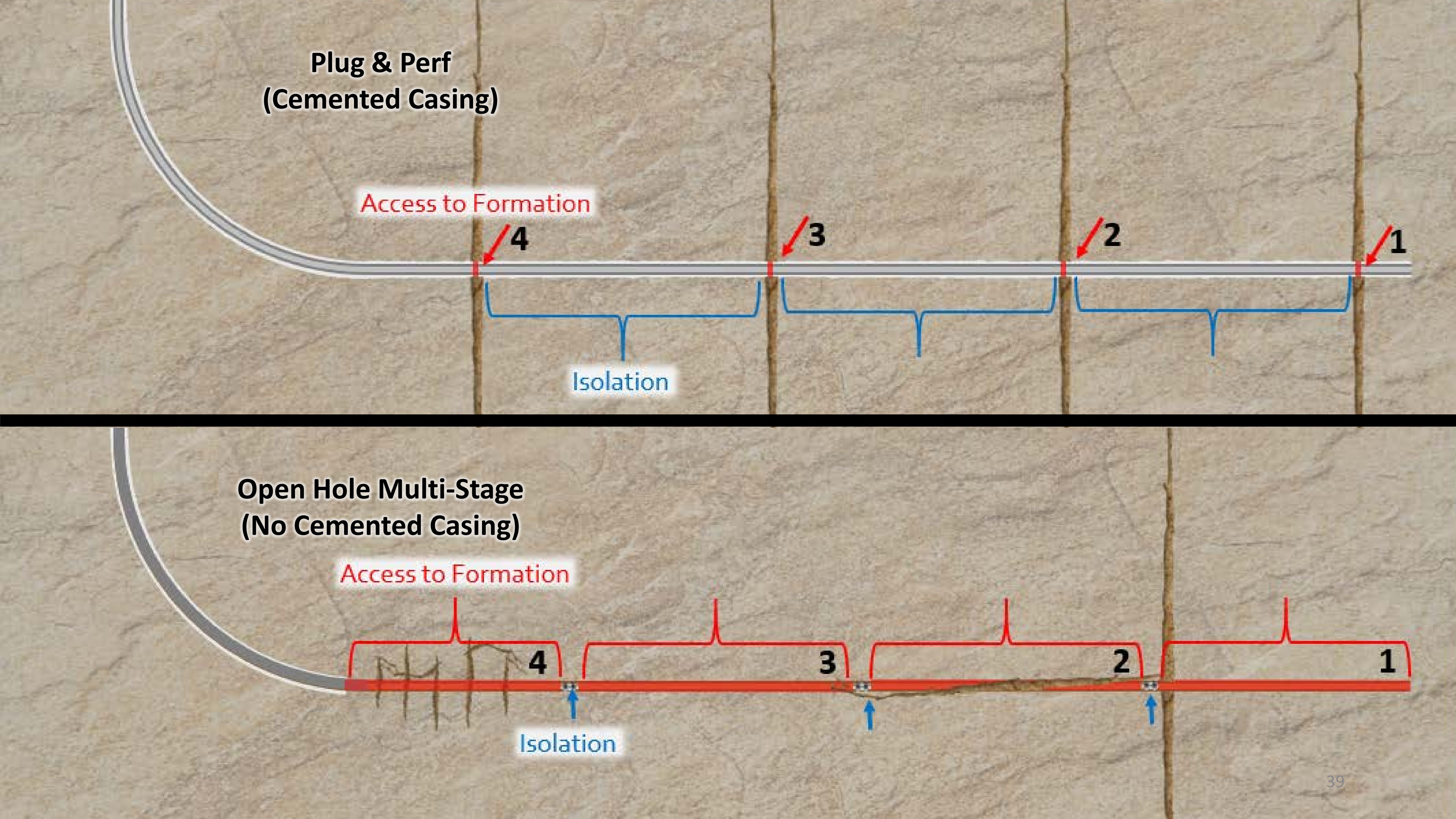







Plug & Perf
(Cemented Casing)
Access to Formation
4
3
2
1
Isolation


Open Hole Multi-Stage
(No Cemented Casing)
Access to Formation
4
3
2
1
Isolation


Plug & Perf
(Cemented Casing)
Access to Formation
4
3
2
1
Isolation
Open Hole Multi-Stage
(No Cemented Casing)
Access to Formation
4
3
2
1
Isolation

Q. What do you mean by that?

A. **You are talking about two systems which are very different in the way they fracture**. In a cemented liner completion, as I mentioned, when you create a fracture, it is where the perforations are. When you use external casing packers, the fracture -- with ports, with fracture ports -- the fracture can be anywhere between the two external casing packers.

Ex. 2016, A. Daneshy Depo. at 21:5-12

When you fracture the well from perforations, your fracture is likely to be right at or very near the perforation. And since the perforations -- the perforated interval in the well is a very short interval. It could be 12 inches, 18 inches, as opposed to open space between two packers that could be 300 feet, 400 feet. So when we say control, that's the extent of it, whether within a few feet or within several hundred feet.

Ex. 2016, A. Daneshy Depo. at 29:8-16

A POSITA would be aware that there was an optimum distance between stages and that fracture spacing was critical to commercial success.

Ex. 2050, McGowen Decl. at 28
Paper 51, POR at 13-15

Q. Why would you care about controlling where a fracture initiates within a 12-to-18-inch span versus a 300-to-400-foot span?

A. Because I want to produce the well in an optimum fashion. It influences the productivity of the well.

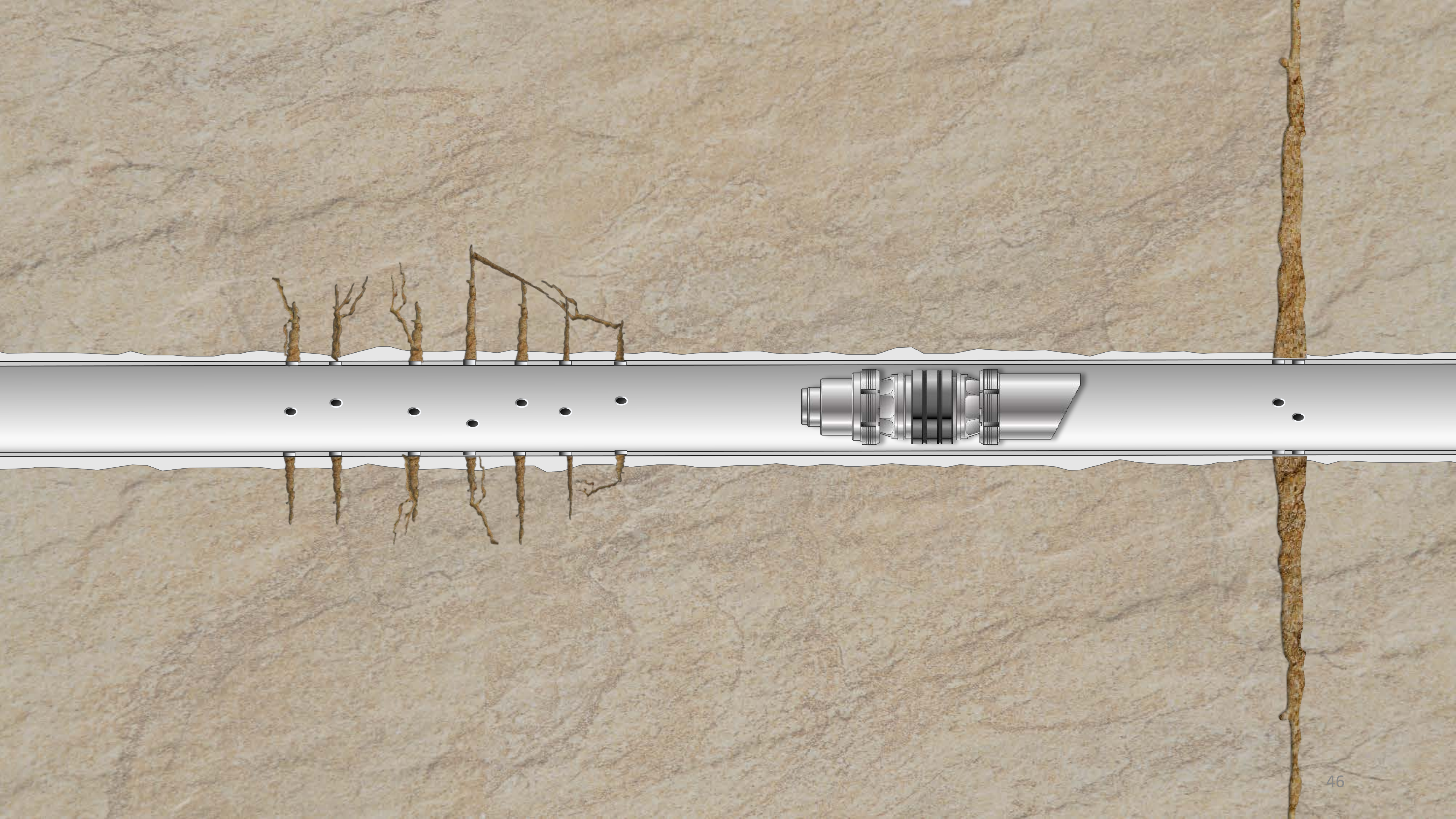
Ex. 2017, A. Daneshy Depo. at 29:17-23

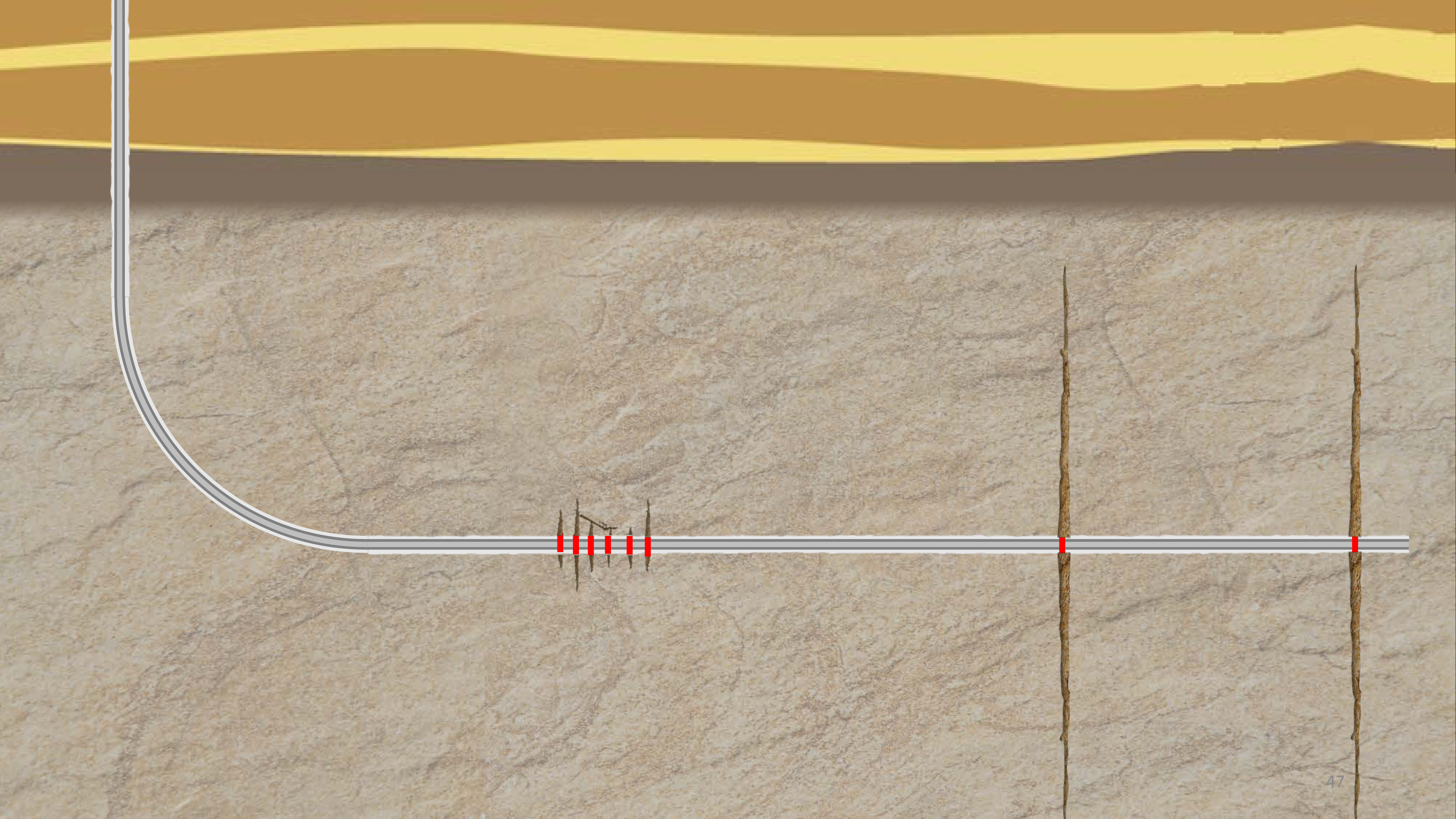
If you put a fracture at plus 10 (which is 10 feet from that packer, on one side of it) and minus 10 (which is 10 feet from the packer on the other side of it), these two packers are 20 feet apart from each other. They basically drain the same segment of the well. You are not getting as much benefit from this as the case when the fracture is in the 100 feet from the packer on one side and 100 feet from the packer on the other side.

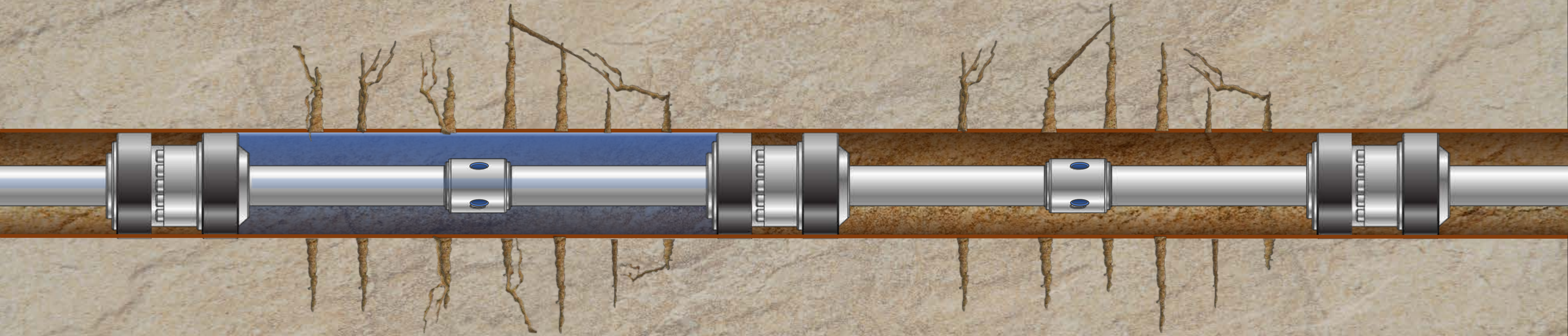
Ex. 2017, A. Daneshy Depo. at 30:6-14

During the period in question, it was thought that the formation of multiple hydraulic fractures that were too close together would also create complex near wellbore fracture geometries that were thought to be detrimental to successful fracture treatments and subsequent production.

Ex. 2050, McGowen Decl. at 29
Paper 51, POR at 13-15







Society of Petroleum Engineers

SPE 39941

A Case History: Completion and Stimulation of Horizontal Wells with Multiple Transverse Hydraulic Fractures in the Lost Hills Diatomite

M A. Emanuele, Chevron U.S.A. Production Company, W.A. Minner and L. Weijers, Pinnacle Technologies, E. J. Broussard and D. M. Blevens, Chevron U.S.A. Production Company and B. T. Taylor, Dowell Schlumberger

This paper was prepared for presentation at the 1998 SPE Rocky Mountain Regional Conference, Denver, U.S.A., 1998.

Abstract

The Lost Hills Field Diatomite has traditionally been developed using vertical wells completed with multiple propped hydraulic fracture treatment stages. As the main portion of the field is nearing full development at 2½-acres per producer, the search for additional reserves has moved out to the flanks of the field's anticlinal structure. Due to limited pay thickness, these flank portions of the field will not support economic vertical well development. The use of horizontal wells was determined to have the best chance to economically develop these areas of the field. To evaluate this development concept, three horizontal wells were drilled and completed over the time period from November 1996 to December 1997.

To assist with the horizontal well design and evaluation, several vertical data wells were drilled offset and parallel to the intended well path of each horizontal well. Additionally, two vertical core wells were drilled in line with the toe and heel of the horizontal well paths. These data wells were utilized to estimate properties such as in-situ stress profiles, pore pressure gradients, rock properties and fluid saturations, and to determine horizontal well vertical depth placement. The horizontal wells were then drilled in the direction of minimum horizontal stress (transverse to the preferred hydraulic fracture orientation) and completed with multiple-staged propped hydraulic fracture treatments.

During the completion of the three horizontal wells, hydraulic fracture growth behavior was characterized using surface tiltmeter fracture mapping and real-time fracture pressure analysis. In the third horizontal well, downhole tiltmeter fracture mapping was also used. This combination of fracture diagnostics provided significant insights into hydraulic fracture behavior, allowing diagnosis of anomalous fracture growth behavior and evaluation of remediation measures. Fracture diagnostics during the first horizontal well revealed an unexpectedly complex near-wellbore fracture geometry, a result of fracture initiation problems. These problems slowed the completion process and severely harmed the effectiveness of the fracture-to-wellbore connection. In the subsequent horizontal wells, a number of design and execution changes were made which resulted in simpler near-wellbore fracture geometry and a greatly improved production response.

The paper provides an overview of the completion and stimulation of all three horizontal wells, describes the lessons learned along the way, and discusses the implications for future Lost Hills horizontal well development.

Lost Hills Field Setting and Horizontal Well Rationale

Field Description. The Lost Hills Field is an asymmetric anticline, approximately one mile wide and twelve miles long, located in Kern County, California, approximately 45 miles northwest of Bakersfield (see **Figure 1**). The anticline trends NW-SE, nearly parallel to the San Andreas Fault. The main reservoir is approximately 1000 ft thick, occurring at depths ranging from 1000 to 3000 ft.

The main reservoir rock is the Belridge diatomite, which has a primary constituent of siliceous shells that are the remains of single-celled, algae-like plants called diatoms. These diatoms were plentiful in the shallow marine environment during the late Miocene (5-10 million years ago), in what is now California's San Joaquin Valley. Due to the open structure and round shape of the small (50 μm-diameter) diatoms, porosity can be as high as 65%, while permeability is typically much less than 1 mD (see **Table 1**). With such high porosity, lithostatic (overburden) gradients are relatively low at 0.79 - 0.82 psi/ft.

The thickness of the reservoir ranges between 600 and 1200 ft. Throughout the field, key reservoir properties change at a depth varying between 1900 and 2700 ft, where the

Ex. 2066
IPR2016-01509

Fracture diagnostics during the first horizontal well revealed an unexpectedly complex near- wellbore fracture geometry, a result of fracture initiation problems. These problems slowed the completion process and severely harmed the effectiveness of the fracture-to-wellbore connection.

Ex. 2066 at 1, Emanuele, SPE 39941 “A Case History: Completion and Stimulation of Horizontal Wells with Multiple Transverse Hydraulic Fractures in the Lost Hills Diatomite” (1998); Ex. 2050, McGowen Decl. at 27-29.

JCPT

Methodology to Predict the Initiation of Multiple Transverse Fractures from Horizontal Wellbores

D.G. CROSBY, Z. YANG, S.S. RAHMAN
University of New South Wales

Abstract

Multi-stage, transversely fractured horizontal wellbores have the potential to greatly increase production from low permeability formations. Such completions are, however, susceptible to problems associated with near-wellbore tortuosity, particularly multiple fracturing from the same perforated interval. A criterion, based on that by Drucker and Prager, has been derived, which predicts the wellbore pressures required to initiate secondary multiple transverse hydraulic fractures in close proximity to primary fractures. Secondary fracture initiation pressures predicted by this new criterion compare reasonably well with those measured during a series of unique laboratory-scale multiple hydraulic fracture interaction tests. Both the multiple fracture initiation criterion and the laboratory results suggest that close proximity of primary hydraulic fractures increases the initiation pressures of secondary multiple fractures by the order of only 14%. This demonstrates that transversely fractured horizontal wellbores have limited capacities to resist the initiation of multiple fractures from adjacent perforations or intersecting heterogeneities. Petroleum engineers can use the multiple fracture initiation criterion when designing hydraulic fracture treatments to establish injection pressure limits, above which additional multiple fractures will initiate and propagate from the wellbore.

Introduction

A significant proportion of the worldwide recoverable hydrocarbon resource exists in reservoirs possessing permeabilities of less than one milli-Darcy (mD). At present, low production rates accompanying such poor permeabilities imply that, if hydrocarbons are to be exploited economically, some form of permeability enhancement or stimulation must be carried out within these reservoirs. Even where initial permeabilities are relatively high, stimulation may still be required to overcome problems associated with localised permeability damage due to, for example, drilling mud invasion. Matrix acidisation and hydraulic fracturing remain the principal reservoir stimulation techniques.

The advantages of horizontal wells in comparison with vertical wells have been extensively documented. Indeed, in an increasing number of fields throughout the world, the production of hydrocarbons is performed exclusively through horizontal wells. Whilst still a relatively rare form of completion, fractured horizontal wells are becoming more common in low permeability formations. This is particularly so where surface geographies dictate that wells must deviate from central drill pads, such as in offshore or arctic regions.

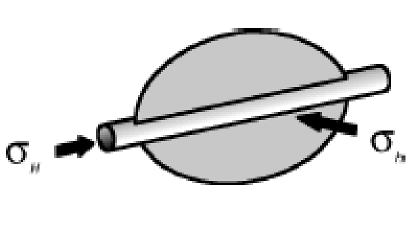


FIGURE 1: Longitudinal fracture configuration.

Hydraulic fractures, regardless of their origin, always attempt to propagate in planes orthogonal to the minimum horizontal stress, in what is commonly referred to as the "preferred fracture plane." However, while hydraulic fracture propagation planes are fixed, the horizontal wellbores from which they emanate may assume completely arbitrary orientations. Two limiting wellbore-fracture configurations are the focus of much attention:

- "Longitudinal Fractures" propagate in planes parallel with wellbore axes, as illustrated in Figure 1. They form where horizontal wells are drilled parallel with the larger of the horizontal stresses (or parallel with the preferred fracture plane);
- "Transverse Fractures" propagate in planes orthogonal to wellbore axes, as illustrated in Figure 2. They form where horizontal wells are drilled perpendicular to the larger of the horizontal stresses (or perpendicular to the preferred fracture plane).

A number of studies have been carried out, comparing the production characteristics between fractured horizontal wells and fractured or unfractured vertical wells[1-5]. In homogeneous reservoirs, longitudinally fractured horizontal wells offer no appreciable productive advantage over similarly fractured vertical wells. Only in thin, high permeability formations will longitudinally fractured horizontal wells significantly outperform fractured vertical wells[1].

Alternatively, transversely fractured wells have the ability to greatly increase production rates by virtue of the fact that any number of fractures may be widely distributed along the length of horizontal wells, as illustrated in Figure 2, through multi-stage treatments. The reduced contact areas between horizontal well-

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Ex. 2039
IPR2016-00598

transversely fractured horizontal wellbores are still plagued by a number of problems, most of which stem from the complex fracture geometries connecting the wellbore to the main fracture. These complex fracture geometries usually take the form of multiple fractures, twisted fractures, H- or S-shaped fractures

Ex. 2063 at 2, Crosby, D.G., "Methodology to Predict the Initiation of Multiple Transverse Fractures from Horizontal Wellbores" (2001); Ex. 2050, McGowen Decl. at 27-29.

Society of Petroleum Engineers

SPE 37354

A Case Study for Drilling and Completing a Horizontal Well in the Clinton Sandstone

William F. Murray Jr., SPE, Belden & Blake Corporation, Leo A. Schrider, SPE, Belden & Blake Corporation, Raymond L. Mazza, SPE, Petroleum Consulting Services, Albert B. Yost II, SPE, U.S. DOE

This paper was prepared for presentation at the 1996 SPE Eastern Regional Meeting held in Columbus, Ohio, 23-25 October 1996.

Abstract

Horizontal well drilling for the recovery of natural gas and oil has been touted as the panacea for optimum recovery from hydrocarbon reservoirs. This technology has been applied to reservoirs throughout the world, primarily in environments such as the North Sea off the coast of Great Britain and the Austinchalk in Southeastern Texas. To date, very few wells have been attempted in the Appalachian Basin. To test this technology in the Appalachian Basin, a joint effort between Belden & Blake Corporation and the U.S. DOE resulted in the first horizontal well successfully drilled and stimulated in the Silurian Clinton Sand formation. The Central Waste #14 well (CW #14), is located in Smith Township, Mahoning County, Ohio, which is one of the better remaining areas for Clinton Sand developmental drilling. The CW #14 was spudded in October 1993 and drilled to a total measured depth of 6,505 feet at a maximum inclination of nearly 92 degrees from vertical with approximately 1,320 feet of Clinton interval exposed. Total Clinton interval footage greater than 85 degrees was about 1,142 feet. Three hydraulic fracturing stages were successfully completed within the horizontal wellbore. Since this was the first horizontal well drilled in the Clinton Sand interval, considerable knowledge and experience was gained in drilling and completing this well. The actual drilling operation required about 45 days of rig time. The well was stimulated during the summer/fall of 1994 and placed on production in early 1995.

The CW #14 was equipped with a pumping unit and downhole pump and has produced approximately 20,000 MCF of natural gas and 7,000 barrels of oil in its first full year of production. Unlike similar wells drilled in this area, the oil production is about twice that expected while the gas production is less than half of the neighboring offsets. Based on the production performance to date which has displayed a much shallower gas decline rate than a vertical well in the area, the CW #14 is currently estimated to have an ultimate recovery in the range of 330 to 400 MMCFE which is approximately 1.6 to 2.0 times its vertical offset wells.

While we are encouraged with the 1.6 to 2.0 increase in estimated ultimate recovery, horizontal drilling does not appear to be a viable economic alternative for primary development in this area without further improvements in reserve potential along with significant cost reductions. At this time, drilling this type well may be limited to special applications for secondary or enhanced oil recovery or perhaps for natural gas storage. The CW #14 horizontal drilling project, however, successfully demonstrated that the extremely hard and abrasive Clinton Sand can be horizontally drilled and stimulated which we considered a major technical accomplishment for drilling a well of this type in the Appalachian Basin.

Introduction

The Clinton Sand is a low permeable gas reservoir in Northeastern Ohio with initial well production generally in the 75 to 150 MCF per day and 5 to 10 barrels of oil per day. Ultimate production from a vertical well in the Clinton formation in Smith Township, Mahoning County is projected to be about 205 million cubic feet of gas

Ex. 2100
IPR2016-01509

[A] decision was made to attempt a cased hole completion with a perforated interval not to exceed two (2) feet. It has been documented in literature and field proven that a smaller focused perforated interval (2 to 3 feet) enables a major fracture system to be initiated rather than several minor fractures which compete for fracturing fluid and ultimately are unable to propagate and extend.

Ex. 2100 at 9, Murray, SPE 37354 “A Case Study for Drilling and Completing a Horizontal Well in the Clinton Sandstone” (1996); Ex. 2081, McGowen Decl. at 24.

Qittitut Consulting

Openhole Multistage vs Plug-n-Perf Completions

Sleeves vs Shots—The Debate Rages

by Richard G. Ghiselin, P.E.

Ex. 2011 at 4

IPR2016-00598

Several years ago, conventional wisdom held that a few widely spaced long length fractures were the best way to fully exploit the reservoir and ensure maximum economic ultimate recovery.

Paper 51,
POR at 25

Qittitut Consulting

Openhole Multistage vs Plug-n-Perf Completions

Sleeves vs Shots—The Debate Rages

by Richard G. Ghiselin, P.E.

Ex. 2011 at 4

IPR2016-00598

Recent experience has shown, however, that numerous closely spaced short fractures produce better results over the life of the reservoir. This outcome would seem to tilt the scale in favor of OHMS owing to its superior efficiency, but OHMS is not the predominant technique in many plays.

Paper 51, POR at 25

A. . . . That’s what a single fracture would have looked like. When you put 20, 30, 40 of these together, then they don't look like that.

Q. What do they look like?

A. Today the industry uses the term “complex” because they don't really know what it looks like.

Ex. 2085, A. Daneshy Depo. at 87:16-23

Q. Are persons of skill in the art today trying to create complex fractures?

A. Yes.

Q. In the past, would a person of skill in the art try and avoid complex fractures?

A. When is "past"?

Q. The time before 2001.

A. Yes, when we fractured vertical wells, we did not want to create complex fractures.

Ex. 2085, A. Daneshy Depo. at 89:11-22

Q. Back before 2001, how did persons of skill in the art expect fractures to behave?

A. They expected them to behave just like they did in vertical wells.

Ex. 2085, A. Daneshy Depo. at 81:8-13

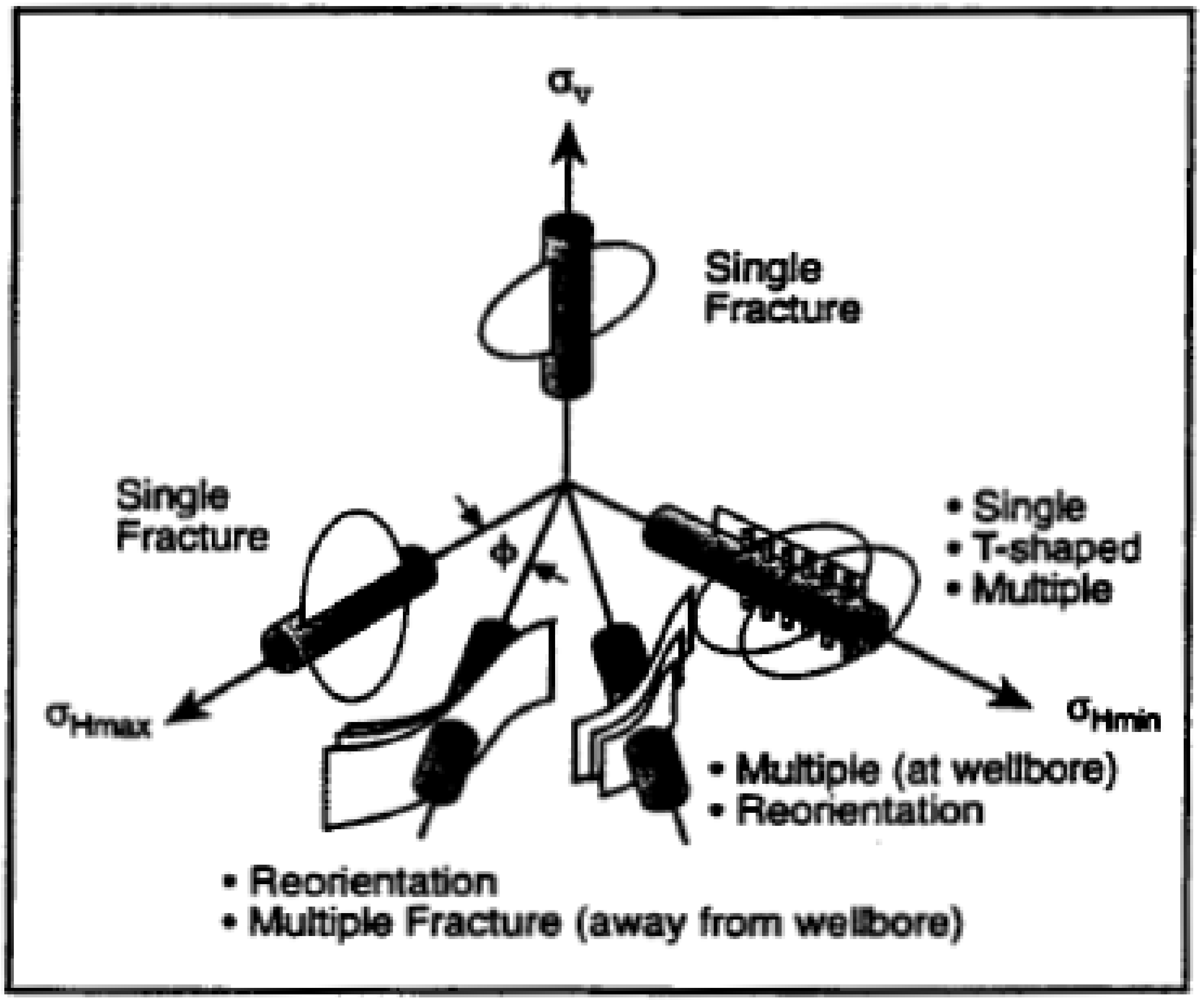

Fig. 6—Nonplanar fracture geometries.

Ex. 2078 at 6 (Abass)

For a normal hydraulic fracturing treatment where proppant is used, if there is a leak around a packer during the hydraulic fracturing ("frac") stage, excessive leak-off could cause a screen out event, resulting in a complete failure of that frac stage and loading the hole up with proppant that would have to be removed at great expense.

Ex. 2034, McGowen Decl. at 33

SPE

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SPE 18263

Simultaneous Multiple Entry Hydraulic Fracture Treatments of Horizontally Drilled Wells

by C.E. Austin and R.E. Rose, Halliburton Services, and F.J. Schuh, Drilling Technology Inc.

SPE Members

II

ABSTRACT

The number of horizontally drilled wells has continued to increase in the past few years. Nearly all of these wells have been completed as "drainholes" with slotted or perforated liner and without a cement sheath. The majority of these have been successful in their designed intent.

Hydraulic fracturing treatments have been performed on a relatively small number of these wells. To be effectively fracture stimulated, a horizontally drilled well must be cased and cemented through the horizontal producing section of the well. Casing and cementing the horizontal section allows fracture initiation points to be controlled in placing multiple fractures.

In situ stresses greatly influence the potential effectiveness of any fracturing treatment procedure. The one factor which most directly affects horizontal wellbore fracturing is the least principal stress, which is at a right angle to the induced fracture. The direction of the horizontal segment of the borehole dictates whether or not the induced fracture will be parallel or at an angle to the borehole.

The use of properly applied controlled entry techniques at several fracture initiation points will help allow equal placement of proppant or reactive fluids in one stimulation treatment. Either fracturing with proppant or fracture acidizing can be used in the stimulation treatment. The potential economic benefit to be derived from a successful multiple entry fracturing treatment merits strong consideration be given to the development of fracturing techniques to help obtain maximum wellbore drainage.

Subject paper explains techniques and methods to be used in creating and placing proppant and/or reactive fluids in each of the multiple fractures in a horizontally drilled well. Economic considerations of the simultaneous stimulation treatment procedure are presented and compared to a vertical well under similar conditions.

References and illustrations at end of paper.

INTRODUCTION

Horizontally drilled wells have been around for the last 50 years. Some of the early attempts were experimental efforts conducted in the Soviet Union in the 1950's,[1,2] where some 43 horizontal wells were drilled at considerable effort with respect to equipment, measurement, and theory. The conclusion drawn from this effort appears to have been that horizontally drilled wells were technically feasible, but economically disappointing. In the 1950's, wells were drilled from the shore in the Long Beach California Field to penetrate a productive offshore horizon. Drilling reached a 90 degree deviation angle and subsequently relaxed to vertical to penetrate the producing zone. Because of the production obtained without setting offshore platforms these wells were both profitable and environmentally acceptable. In the 1970's, Mobil, et al. drilled a highly deviated well into the Pine Island Chalk. The well was stimulated by hydraulic fracturing through multiple fracture initiation points. Each of the initiation points was treated separately. As a result of the technology developed for this experiment, Mobil was issued a patent in 1974.[3] Again though, the conclusion based on Mobil's experience appeared to be that horizontal or highly deviated wells were technically feasible but economically disappointing.

The development of better directional drilling techniques resulting from experience

Ex. 2098

IPR2016-01509

To be effectively fracture stimulated, a horizontally drilled well must be cased and cemented through the horizontal producing section of the well. **Casing and cementing the horizontal section allows fracture initiation points to be controlled in placing multiple fractures.**

Ex. 2098, Austin, SPE 18263, Simultaneous Multiple Entry Hydraulic Fracture Treatments of Horizontally Drilled Wells at 1 (1988); Ex. 2081 at 24-25; Ex. 2081, McGowen Decl. at 24-25; Paper 51, POR at 20-21.

SPE 25058

Society of Petroleum Engineers

Practical Considerations of Horizontal Well Fracturing in the "Danish Chalk"

K.A. Owens and M.J. Pitts, Maersk Oil & Gas A/S, and H.J. Klampferer and S.B. Krueger, Halliburton Services

SPE Members

This paper was prepared for presentation at the European Petroleum Conference held in Cannes, France, 16–18 November 1992.

ABSTRACT

Placement of a propped hydraulic fracture in a horizontal well is dependent on several parameters. These parameters include topics such as reservoir conditions, drilling practices, and completion techniques. This paper outlines some of the practical considerations that must be accounted for during the placement of proppant in a horizontal well. In describing a propped fracture treatment on an offshore horizontal well, the paper discusses treatment design considerations and verifies the operational and logistical improvements which can be made by utilizing a state-of-the-art stimulation vessel.

INTRODUCTION

Hydraulic fracturing of horizontal wells is often attractive for a formation where conventional wells drilled in the vertical condition also require this type of treatment. The Dan field in the Danish sector of the North Sea is no exception to this philosophy. The field, discovered in 1971, is produced from the Tertiary Danian and Cretaceous Maastrichtian chalks, typified by high porosities (30%) and low permeabilities (1 md). Since the start of development, all conventional deviated wells in this field were fracture stimulated to improve productivity. However, post stimulation production results were disappointing. A feasibility study performed on application of horizontal wells in the Dan field concluded that horizontal wells were economically attractive only by fracture stimulating multiple zones in the drainhole section and maintaining appropriate zonal isolation.[1-3] Therefore, in 1987 the operator commenced drilling of horizontal wells to increase the field's production potential.

The initial Dan horizontal wells were stimulated with acid fracture treatments, the industry standard for a chalk reservoir. The placement of these treatments proved effective, however, the medium term production was limited due to the low formation integrity and consequent collapse of the induced fracture system. Propped fracture treatments replaced the acid treatments and the benefits to productivity were quickly seen. However, the placement of proppant into some of the Dan horizontal wells became difficult, and in some cases impossible. The difficulties in placement are attributed to several factors. Principal among these is the direction of the horizontal wellbore relative to the preferred direction of the induced fracture.[4] The situation is further complicated by the varying nonconformities that can exist at the near wellbore area.[5]

The theory and completion philosophy utilized in performing multiple fracturing treatments in horizontal wells has been the topic of several previous papers.[6-10] This paper will present

References and illustrations at end of paper.

DEFINV00005462

Ex. 2099
IPR2016-01509

A horizontal well that is to be fracture stimulated over multiple zones **must** be cased and cemented.

Ex. 2099, Owens, SPE 25058, Practical Considerations of Horizontal Well Fracturing in the "Danish Chalk" at 2 (1992); Ex. 2081, McGowen Decl. at 23; Paper 51, POR at 20-21.

SPE 29443

A Case History of Completing and Fracture Stimulating a Horizontal Well

Hazim H. Abass,** Peter Hagist,* James Harry,† James L. Hunt,** Mark Shumway,† Naz Gazi**
*Pennzoil, **Halliburton Energy Services, †Choctaw II Oil and Gas, Ltd.

SPE Members

This paper was prepared for presentation at the 1995 SPE Production Operations Symposium, Oklahoma City, April 2-4.

Abstract

This paper presents a detailed description of the completion and fracture stimulation of a high-angle well in the Madison formation of the Williston Basin in North Dakota. The case history of the Candee 26-13 HA well is used. The completion and fracture stimulation techniques used on this well resulted in a three and a half-fold increase in the ultimate recovery of the well, in comparison to a vertical well in the same field.

The well was directionally drilled to intersect natural fractures and provide optimal conditions for hydraulic fracture stimulation. To ensure zone selectivity and isolation, the well was cased and cemented. Notching techniques were used to allow hydraulic fracture treatments to be selectively initiated along the wellbore. Matrix acidizing was an essential phase to achieve this goal.

This paper also presents a discussion of how reservoir simulators can be used to optimize the number of fractures needed to cover a given drainage area. In addition, prefracture and postfracture evaluations are discussed.

References at the end of the paper.

Introduction

The primary benefit of drilling a horizontal well is to take advantage of a greater effective drainage area than that available from a vertical well drilled in the same area. Fracturing a horizontal well has presented problems because of premature screenouts and high treatment pressures. In most geological formations, the orientation angle of a horizontal well from the maximum horizontal stress plays a crucial role in achieving a successful stimulation treatment. The following three mechanisms related to wellbore orientation relative to the maximum horizontal stress (orientation angle) need to be addressed.[1]

- *Fracture-wellbore communication area.* Two extreme cases, longitudinal and orthogonal fractures, provide maximum (longitudinal) and minimum (orthogonal) communication area between the wellbore and propagating fractures.
- *Fracture geometry near the wellbore.* Fracture geometry is an important factor that may cause early screenouts. Several different fracture geometries can result when a horizontal well is fractured, including multiple fractures, T-shaped fractures, and complex fractures.

Ex. 2055
IPR2016-00598

Casing and cementing a horizontal well is **essential** to provide zone selectivity and isolation during fracture stimulation.

Ex. 2078 at 9, Abass, H., “A Case History of Completing and Fracture Stimulating a Horizontal Well” SPE 29443 (1995); Paper 51, POR at 20-21.

SPE 29443

Society of Petroleum Engineers

A Case History of Completing and Fracture Stimulating a Horizontal Well

Hazim H. Abass,** Peter Hagist,* James Harry,† James L. Hunt,** Mark Shumway,† Naz Gazi**
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Ex. 2055
IPR2016-00598

Perforations play a **crucial role** in achieving a successful fracturing treatment in horizontal wellbores.

Ex. 2078 at 9, Abass, H., “A Case History of Completing and Fracture Stimulating a Horizontal Well” SPE 29443 (1995);

Paper 51, POR at 20-21.

and rapidly flattens after four to five fractures. Based on the diminishing slope of the cumulative production vs. time curve at 24 months, four or five fractures would be the most effective number of fractures for the subject well. However, after considering the behavior of the well/fracture system, designers considered economics and selected three fractures for the subject well.

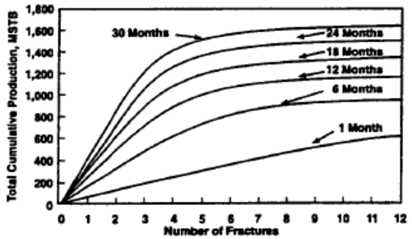

Fig. 7—Cumulative liquid production vs. the number of fractures for various times after fracturing.

Stimulation Treatment

The stimulation treatment was designed to achieve the following objectives:

- *To create a cavity near the wellbore.* To ease the near-wellbore restriction, an acid stage was used to communicate all the hydrojetted notches. **Fig. 8** presents a schematic of the longitudinal slots created via hydrojetting. **Fig. 9** shows a conceptual representation of what might have happened after an acid treatment. **Fig. 10** shows the creation of the main fracture as it initiates from the cavity.
- *To prevent the natural fractures intersecting the wellbore from initiating and propagating multiple fractures.* For fluid-loss contol, 100-mesh sand was pumped after the pad.
- *To help withstand the high compressive stress near the wellbore and reduce the pressure drop resulting from the radial flow convergence.* High-strength, coarse proppant was used as a tail-in stage.

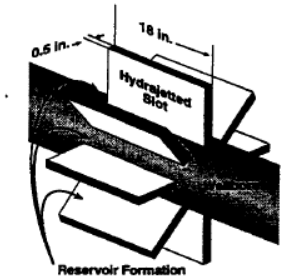

Fig. 8—Longitudinal slots created by hydrojetting.

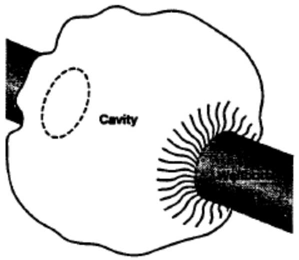

Fig. 9—Conceptual representation of what might have happened after an acid treatment.

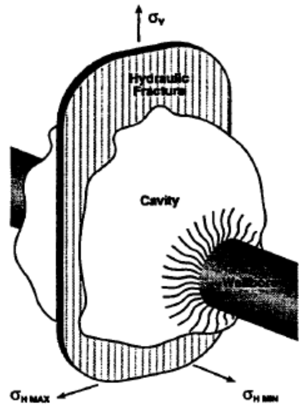

Fig. 10—Creation of the main fracture as it initiates from the cavity.

The stimulation treatment was designed to achieve the following objectives:

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Ex. 2078 at 9, Abass, H., "A Case History of Completing and Fracture Stimulating a Horizontal Well" SPE 29443 (1995); Paper 51, POR at 20-21.

A Unique Method for Perforating, Fracturing, and Completing Horizontal Wells

A.P. Damgaard, SPE, Maersk Energy Inc., and **D.S. Bangert,** SPE, **D.J. Murray, R.P. Rubbo,** SPE, and **G.W. Stout,*** SPE, Baker Oil Tools

SPE 19282

Summary. This paper describes the evolution, laboratory testing, and field installation of a completion system developed to perforate, fracture stimulate, and isolate multiple zones in North Sea horizontal wells. This system is designed to reduce overall completion time and well control problems significantly and to allow selective zone control in production and restimulation phases. The field performance of this system is compared with that of previously used methods.

Background

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

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

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

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

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

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

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

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

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

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

Development of Method

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

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

*Now at The Western Co.

Successful liner installation and **cementation is considered a prerequisite** to ensure adequate zonal isolation for multiple fracture treatments in horizontal wells.

Ex. 2079 at 1, Damgaard, A.P., “A Unique Method for Perforating, Fracturing, and Completing Horizontal Wells” SPE 19282 (1992); Paper 51, POR at 20-21.

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SPE International
Society of Petroleum Engineers

SPE/Petroleum Society of CIM 65464

Application of Hydraulic Fractures in Openhole Horizontal Wells

P. D. Ellis, SPE, Golden Okie Associates, Inc., G. M. Kniffin, SPE, and J. D. Harkrider, SPE, Apex Petroleum Engineering

This paper was prepared for presentation at the 2000 SPE/Petroleum Society of CIM International Conference on Horizontal Well Technology held in Calgary, Alberta, Canada, 6-8 November 2000.

Abstract

This paper describes a process that has improved production, reduced costs, saved time, and dramatically improved the results of fracture stimulating low permeability horizontal wells. The use of both propped and acid fracture treatments will be described.

The process has been used for openhole completions aligned in the approximate direction of fracture propagation as well as for fractures transverse to the well bore. The technique has effectively eliminated well bore connectivity problems that had been observed in vertical completions and cased and cemented horizontal wells with transverse fractures.

The process has been used to increase production over 25 fold in a 30 year old field. It has also proven successful in a marginally economic field that had been completed using propped fractures in vertical wells.

The procedure employs a system of multiple, retrievable treating subs that are specifically tailored to a unique well bore configuration and allow treating the entire interval with a single stage. The treating subs are designed to distribute the treating fluid as desired along the length of the lateral. The process has been successfully used in over 100 wells and laterals in fields located in California, Illinois, New Mexico, Utah, and Texas.

Introduction

History of Horizontal Wells[1,2]. Horizontal and high angle wells have been envisioned and/or used for approximately 80 years. Patents were filed in the early 1920's in the United States, but the tools were never fully developed. Horizontal wells re-emerged in the 1940's and 50's, but were displaced when hydraulic fracturing was developed in the late 1940's and early 50's. Horizontal wells were used in the Soviet Union and China during the 1950's and 60's. A heightened interest in horizontal well resurfaced in the late 1970's due to the increased directional control developed for offshore drilling. By 1985 further advances in horizontal drilling techniques and production response led to a boom in horizontal wells.

Well Paths[1]. Many different well paths are considered "horizontal" besides a flat path. Common trajectories include inclined, both up and down, wavy or undulating, multilevel, and multilateral, or depending on the application very complicated. Fig. 1 shows some of the more common well paths.

Common Uses[1,2,3]. Horizontal wells increase production by contacting more reservoir rock; intersecting natural fractures; reducing gas or water coning at a given production rate or drawdown; improving sweep efficiency in secondary and tertiary recovery projects; and improving gravity drainage in low pressure reservoirs. Ideally, the horizontal well should be completed openhole to take full advantage of the increased reservoir contact. This is not always possible due to wellbore stability problems or undesired fluid entry.

BAKER HUGHES INCORPORATED AND BAKER HUGHES OILFIELD OPERATIONS, INC.
Exhibit 1023
BAKER HUGHES INCORPORATED AND BAKER HUGHES OILFIELD OPERATIONS, INC. v. PACKERS PLUS ENERGY SERVICES, INC.
IPR2016-00598

ffective ... e is not ... ered to ... simple ... ulation, ... is not a ... plexity ... solation ... casing ... ed in an

Typically, the most common method of isolation is cementing casing in the horizontal. Unfortunately, this isolates not only the problem but also the reservoir from the

In the Red Oak horizontal, the geologic expectation was to cross natural fractures and yield economic production without fracture stimulation. Natural fractures were not encountered and production was uneconomic from the openhole. Thus, the contingency plan to set and cement a liner to pump multiple transverse fractures was implemented.

Ex. 1023 at 3, P.D. Ellis, Application of Hydraulic Fractures in Openhole Horizontal Wells, SPE 65464 (2000); Paper 41 Surreply at 3.

implementation. Among these complications is the hole navigation. The production outcome of a horizontal hole depends greatly on the location of the hole relative to the formation. For example, delaying water production requires placing the horizontal hole close to the top of the reservoir. Without water or gas, best production results come from a hole which is at the centre of the reservoir. Given the complex geology and structure of most reservoir formations, placing the well at the desired part of the formation can become a daunting task. Consider the structure shown in **Fig. 4 A**. A straight horizontal hole in this formation will intersect the water zone and lose most of its advantages. The success of the horizontal hole depends on the ability to steer the well properly within the reservoir. For example, the case shown in **Fig. 4 B** satisfies the requirement for distance from the oil/water contact, but it could face operational problems due to hole curvature and the possibility of debris collection at the bottom of the well, thus impeding flow of reservoir fluid. A shorter and better placed hole can offer better production results, as shown in **Fig. 4 C**. Obviously the challenge here goes beyond planning and drilling operations. It mandates superior reservoir mapping and characterization.

At the present time, most horizontal holes are completed openhole. The main reasons for this choice are:

- The main benefit of horizontal holes comes from their long contact with the permeable reservoir. Casing and perforating these holes reduces this contact. However, whenever completion operations require hydraulic fracturing, the horizontal holes are in fact cased, cemented, and perforated to facilitate effective fracturing.
- Contrary to initial fears, in many formations hole stability has not been a big problem. This is specially true in those areas where the maximum *in situ* principal stress is horizontal. Concerns about hole stability have sometimes been addressed by placing slotted or perforated liners inside the horizontal section.
- Since drilling a horizontal hole costs more and takes longer, part of the added cost is offset by openhole completions.
- Cemented completion of horizontal holes is still uncharted territory for many operators and therefore preference is given to alternative completions.

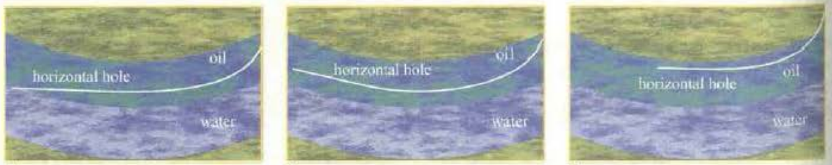
More discussion of horizontal hole completions are presented later in this chapter.

3.1.3 Multilateral wells

Side-tracking off of an existing well and drilling a branch well has long been an established practice of the oil and gas industry. In the past, the use of this technique was limited to problem wells where continuation of the existing well path was either impossible or very costly. The process consisted of placing a high strength cement or mechanical plug inside the well to divert the bit into a new path. But doing this left the original hole plugged and inaccessible for future production or operations.

With the feasibility and benefits of horizontal wells verified by actual applications, industry innovators quickly considered extension of the process for more robust production schemes. Several groups, mostly in the North Sea, began planning for completion architectures involving production from multiple horizontal holes connected to a mother bore. Among these were groups such as Maersk, BEB, Norsk Hydro, BP, and service companies such as Halliburton and Baker. Although the side-tracking technology was mature and well-established, new technologies were needed to allow the selective re-entry of various laterals, as well as commingled production from them.

The technology for side-tracking and drilling off of existing wells had been in existence for many years. Almost all of these side-tracked wells were mandated by drilling problems that made continuation of the existing bore either impossible or very costly. But in all these applications, the original



A B C

Fig. 4. Different hole layouts in a horizontal hole: A, undesirable orientation with respect to oil/water contact; B, hole tracking oil/water contact; C, the same as B, but with a shorter and better placed hole.

The main benefit of horizontal holes comes from their long contact with the permeable reservoir. Casing and perforating these holes reduces this contact. However, **whenever completion operations require hydraulic fracturing, the horizontal holes are in fact cased, cemented, and perforated to facilitate effective fracturing.**

Ex. 2015, Encyclopedia of Hydrocarbons, at p. 8 (2007); Paper 51, POR at 21.

SPE 164009

Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics.

Alberto Casero, Hammed Adefashe, Kevin Phelan, BP America Inc.

This paper was prepared for presentation at the SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28–30 January 2013.

Abstract

During the past decade, the combination of hydraulic fracturing and horizontal wells, has proven to be the key, to the unlocking of unconventional plays across North America and elsewhere. This efficiency has been accomplished by using two very distinct completion approaches: the Plug and Perf. method and the Open Hole Multi Stage (OHMS) completion system (typically ball activated fracturing ports).

The OHMS completion system has in general been applied to carefully selected fields and has not yet gained wider acceptance, across the industry, as a viable alternative to the more popular and extensively utilised Plug and Perf approach. This resistance to change and the reluctance to consider alternative completion approaches, are due to a number of factors, many of which reflect an operational comfort zone from which there is a hesitancy to stray. Often the disadvantages of the OHMS approach may be overemphasized, while the associated advantages are not suitably considered and vice versa for the Plug and Perf approach.

Case histories from a number of North American unconventional plays, for example the Red Oak, the Cotton Valley and the Granite Wash, will be both presented and analyzed. This analysis will focus on a number of aspects, including the hydraulic fracturing treatments, the operational efficiencies, the cost effectiveness and the overall risk reduction aspects of the OHMS vs. the Plug and Perf approaches.

Introduction

Over the past decade, the Oil and Gas industry has considerably increased the well completion activity levels taking place across the unconventional plays within North America. Continued advancements in both the completions technologies and the operational techniques, particularly when combining horizontal drilling and hydraulic fracturing, have allowed an efficient access to previously uneconomic resources to be achieved. These previously uneconomic resources comprise of a number of different plays, consisting of various pore fluids, formation lithologies and hydrocarbon trapping mechanisms. In this respect, the tight gas-sands, coal bed methane (CBM), shale gas and more recently shale oil opportunities can all be considered a part of the unconventional resource grouping.

Fundamentally, the reasoning behind the consideration of horizontal well drilling is fairly simple, horizontal wells will provide an additional amount of contact area within the reservoir and by this means an improved production rate compared to a vertical well can be achieved. However, the reality is not as straightforward and the increased surface area, exposed to the reservoir, is not the only factor directly affecting this enhanced production rate.

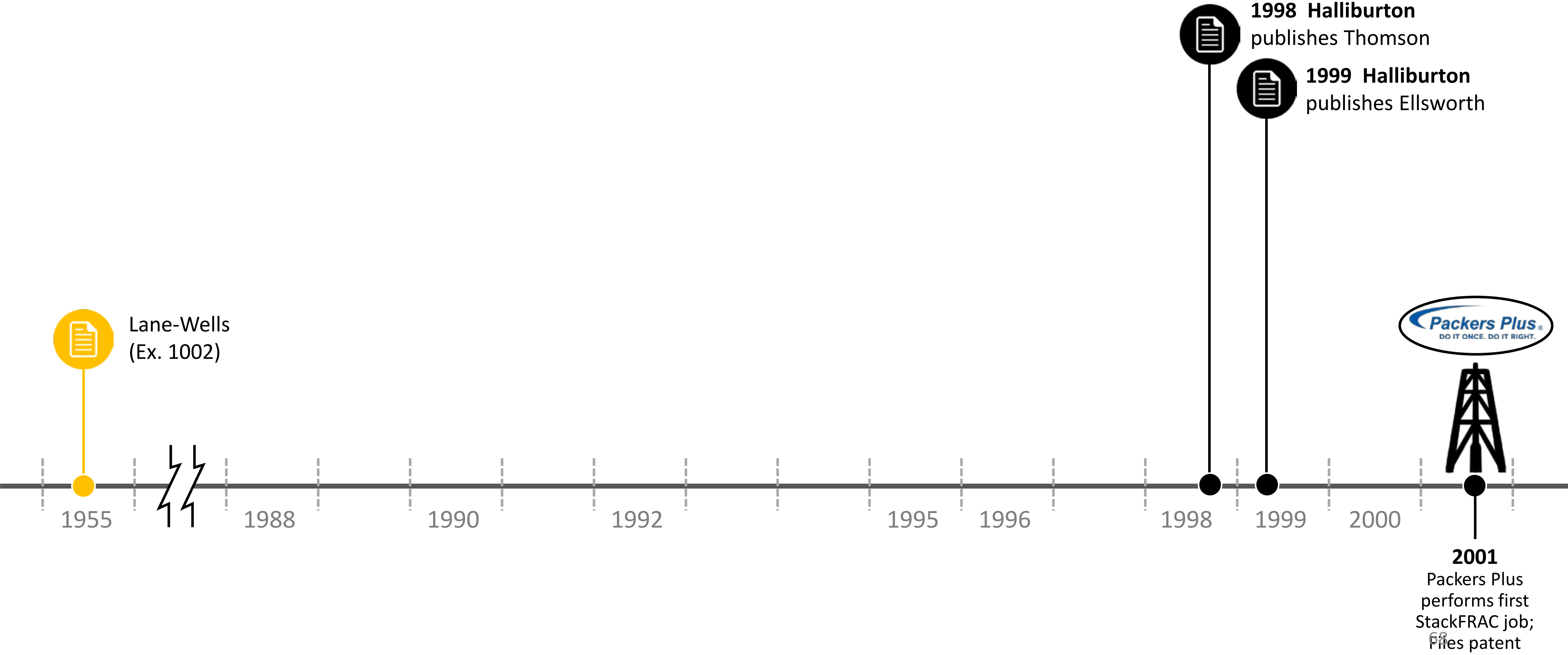
In order to explain more clearly, consider the simple derivation of the Darcy flow equation for an ideal liquid, for a vertical well (1), written in oilfield units. This equation simply states that the production rate (q) is directly proportional to the applied drawdown (Δp), the reservoir thickness (h), the formation permeability (k), the wellbore radius (r_w) and is also inversely proportional to the pore-fluid viscosity (μ) and the fluid formation volume factor (B).

$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \quad \ldots (1)$$

Exhibit 2001
IPR2016-00598

Some of the features of the OHMS approach are often depicted as disadvantages, such as the inferred inability to control the initiation point of the fractures. . . .

Ex. 2001 at 5, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013); Paper 51, POR at 22.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performs first
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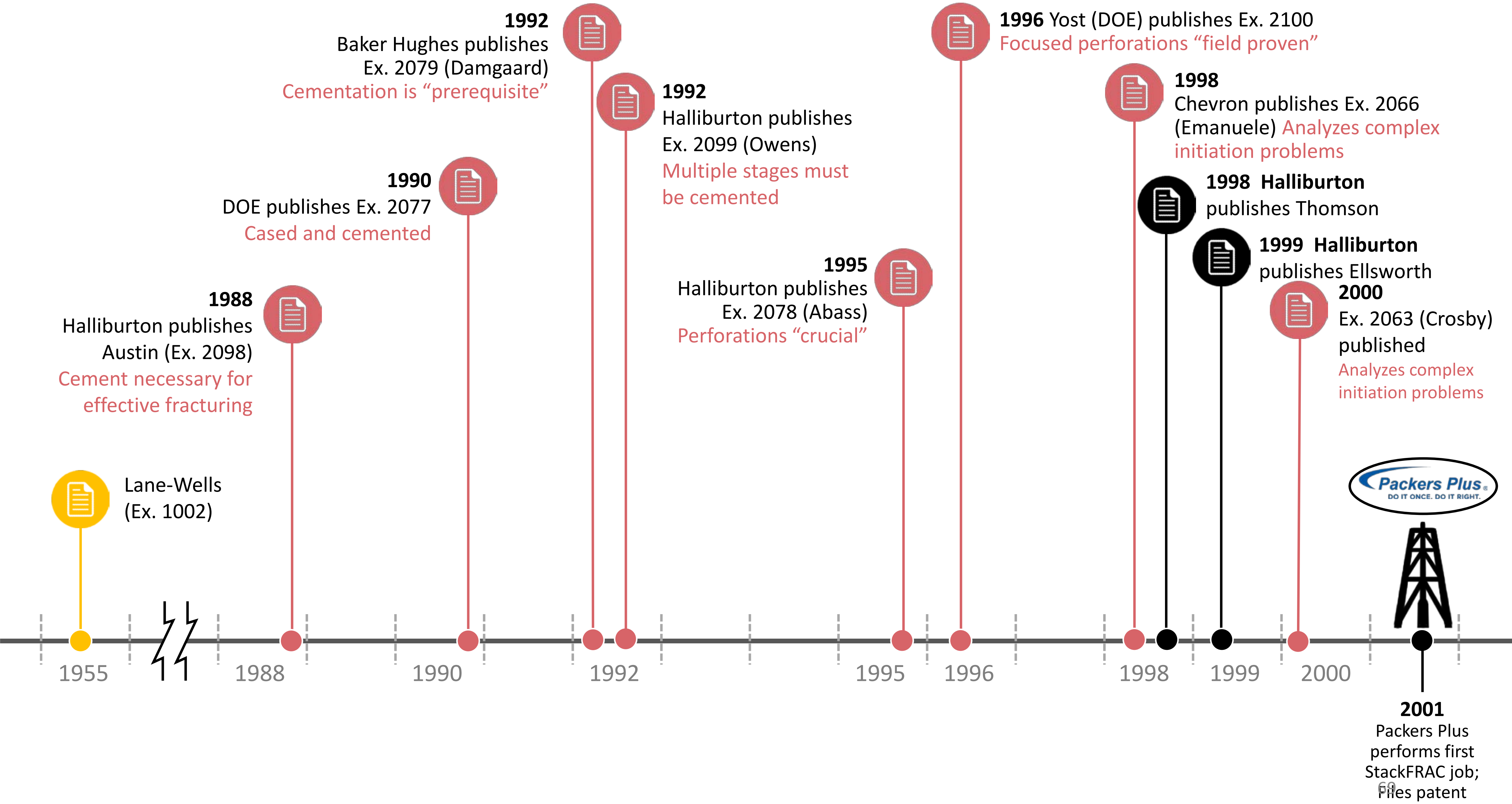

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Ex. 2079 (Damgaard)
Cementation is "prerequisite"
1992
Halliburton publishes
Ex. 2099 (Owens)
Multiple stages must
be cemented
1990
DOE publishes Ex. 2077
Cased and cemented
1988
Halliburton publishes
Austin (Ex. 2098)
Cement necessary for
effective fracturing
Lane-Wells
(Ex. 1002)
1995
Halliburton publishes
Ex. 2078 (Abass)
Perforations "crucial"
1996 Yost (DOE) publishes Ex. 2100
Focused perforations "field proven"
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Packers Plus
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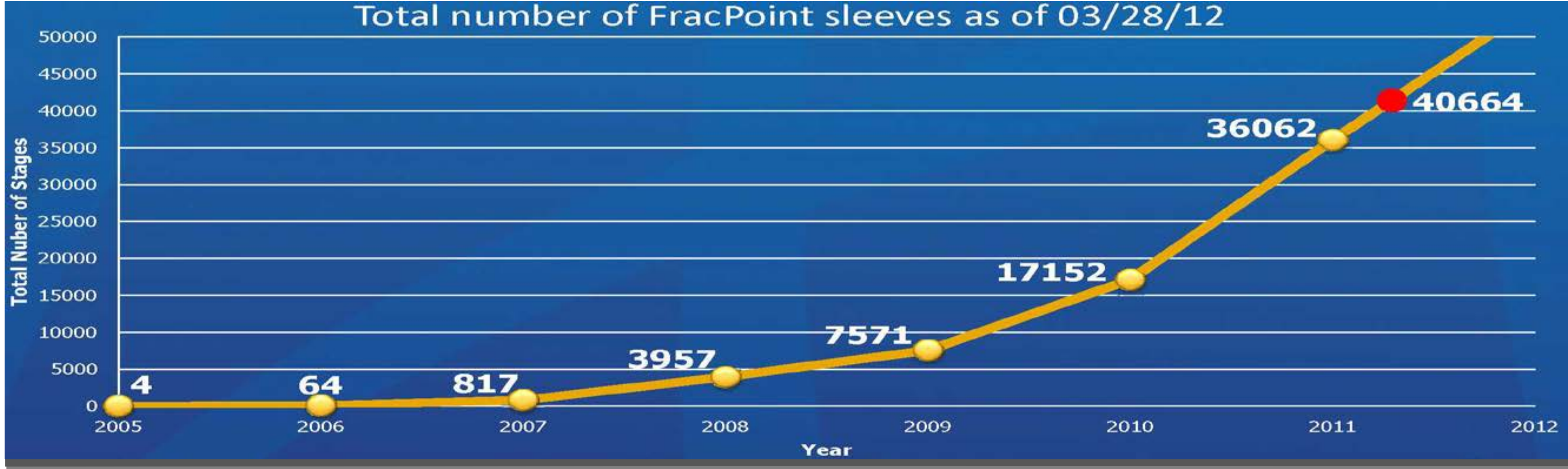

BAKER HUGHES

Packers Plus
DO IT ONCE. DO IT RIGHT.

2001
Packers Plus performs first StackFRAC job; Files patent

2003
Baker Hughes obtains Packers Plus tool drawing

2005
Baker Hughes releases FracPoint

2005
Schlumberger acquires stake in Packers Plus

2006
Packers Plus publishes Ex. 2003

A. Daneshy 2007
Ex. 2014 published
Still advocating cement

2009
Packers Plus named E&Y Entrepreneur of the Year

Weatherford releases Zoneselect

2010
Packers Plus receives SPE Meritorious Engineering Award

Sproule

2012
Packers Plus receives Sproule Engineering Award

2003 2005 2006 2007 2009 2010 2012

The POSITA would have been aware that there is a significant economic risk associated with adopting new technology and/or methods that defy “tried and true” technology and/or methods.

Ex. 2050, McGowen Decl. at 24
Paper 51, POR at 15-17

SPE 164009

Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics.

Alberto Casero, Hammed Adefashe, Kevin Phelan, BP America Inc.

This paper was prepared for presentation at the SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28–30 January 2013.

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$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \qquad \ldots (1)$$

Exhibit 2001
IPR2016-00598

The P&P approach was the initial lower completion methodology that allowed the effective deployment of multi-fracture treatments in horizontal wells and **it is difficult to progress from an established, standardized and successful technique**; unless there are significant tangible benefits that can be demonstrated via a different method.

Ex. 2001 at 5, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013)

[A]nother, for example, reason you would use cemented liner is because your neighbors are using cemented liner and you're getting a better production and you say, “I don't know why they’re doing it but they're getting better production. I’m going to use what they are using.”

Ex. 2016, A. Daneshy Depo. at 26:2-10

SPE 98511

Accelerating Technology Acceptance: Hypotheses and Remedies for Risk-Averse Behavior in Technology Acceptance

V. Rao, Halliburton Co., and R. Rodriguez, Shell Technology Ventures

This paper was prepared for presentation at the 2005 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, U.S.A., 9–12 October 2005.

Abstract

Risk aversion was concluded as being a significant factor in the observed slow uptake of technology in the Upstream Sector of the Oil and Gas business. Hypotheses centered on information asymmetry, effect of risk volatility on tolerance, and risk profiles of decision makers molded by structural or temporal considerations. Remedies proposed for debate and action included the creation of industry wide independent entities (testing agency or insurance company) charged with closing the gap created by asymmetries, as well as the creation of an industry award for excellence in technology uptake.

Background

This paper attempts to summarize a series of discussions held by a technical breakout group, as part of the larger SPE Applied Technology Workshop on Accelerating Technology Acceptance held on March 15-16, 2005 at the Del Lago Resort in Montgomery, Texas, USA. Approximately one hundred (100) attendees participated in the ATW, with six technical breakout sessions conducted during the 2-day workshop. Topics covered included Nucleating and Funding E&P Technology, Prioritization and Assessment, Incentives/Compensation and Culture, Blurring the Lines, and Technical Backbone.

Some of the concepts discussed within the ATW were reported in an earlier article published in the May 2005 issue of the Journal of Petroleum Technology titled *Annual Drilling Conference Probes Technology Development and Lessons Learned*[i], which reported on discussions held at the SPE/IADC Drilling Conference and Exhibition in Amsterdam earlier this year. The article expanded on the concept that the *speed of technology uptake* is an important problem faced by our industry. The SPE was subsequently encouraged by readership response to hold an Applied Technology Workshop in order to produce a platform for the discussion of remedies.

Below we summarize some of the discussions held within the specific breakout session tasked with understanding the roles played in technology uptake from a *risk and reward* perspective. While the paper represents in large part the findings of the group, further influenced by discussion in the larger forum of the ATW members, the authors alone are responsible for the views expressed below, including the weight placed on the different hypotheses and remedies. We therefore have written this paper in the form of a normal publication, and acknowledge that its content is neither an actual accounting of discussions which took place, nor is it necessarily faithful to the chronology of events.

Methods

A breakout group of about twenty-two persons considered the stated problem:

Problem: Risk aversion is likely an important reason for slow technology uptake.

It was generally presumed that the technologies in question have demonstrated application suitability with early adopters. Upstream technologies comprised the single focus of discussions. A presentation of macro economic trends having likely influencing behavior was given, followed by a moderated discussion. The general concepts surrounding risk-taking were also discussed and examples were provided. Basic ground rules were laid out: Hypotheses for the observed behavior would be put forward and discussed, and the group would rank the most relevant hypotheses. In some instances hypotheses were combined into logical groupings. The breakout group would then advance those specific remedies that addressed one or more of the chosen hypotheses. These in turn would be ranked for eventual

Ex. 2093
IPR2016-01509

Risk aversion was concluded as being a significant factor in the observed slow uptake of technology in the Upstream Sector of the Oil and Gas business.

Ex. 2093 at 1, V. Rao, Accelerating Technology Acceptance: Hypotheses and Remedies for Risk-Averse Behavior in Technology Acceptance, SPE 98511 (2005)

SPE 135386

Comparative Study of Cemented Versus Uncemented Multi-Stage Fractured Wells in the Barnett Shale

Darrell Lohoefer, SPE, Eagle Oil & Gas, and Daniel J. Snyder, SPE, Rocky Seale, SPE, and Daniel Themig, SPE, Packers Plus Energy Services

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Florence, Italy, 19–22 September 2010.

Abstract

The industry has made a very quick turn toward both unconventional reservoirs and horizontal, multi-stage fracturing. Some industry experts have begun to question the effectiveness of recoveries in these massive reserve assets. A notable formation in these discussions has been the Barnett Shale, where a variety of methods and technologies have been used to fracture stimulate horizontal wells. In fact, much of the learning curve for completion practices has come from experimental work in this unconventional play.

From 2004 through 2006, a new, open hole, multi-stage system (OHMS) completion technology was run in Denton County, Texas. Using publically available data from the past five years, this study contrasts long-term production results from OHMS completed wells and wells completed with cemented casing.

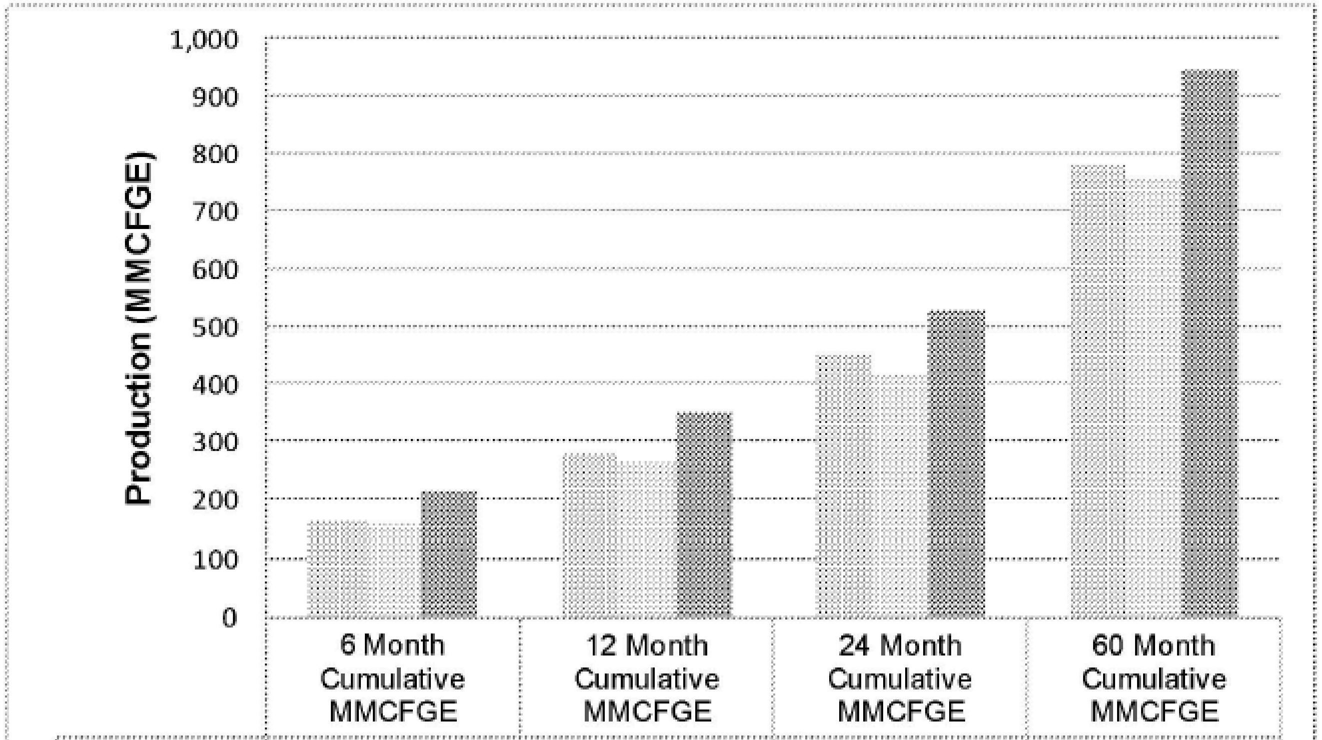
The data set for OHMS fractured wells compared to the data set for cemented fractured wells indicates that open hole wells, on average, performed better. Significantly, no failures or shut-in periods were observed for the OHMS wells. This establishes the viability, reliability and effectiveness of this technology for the long-term life of wells not only in the Barnett, but for performance enhancement in other shale plays.

Substantial amounts of money are currently being spent to rapidly develop resource plays similar to the Barnett worldwide. Based on short-term results using current completion methods, predictions for ultimate recoveries may be overestimated. This paper evaluates the effectiveness of current completion practices by contrasting two methods in terms of production, economics, operational efficiency, and best fracturing practices to determine whether the completion method can affect overall well performance and long-term recovery.

Introduction

Formation Description. The Barnett Shale is a Mississippian-age shale located in the Forth Worth Basin and covers approximately 5,000 square miles (12,950 km^2) of north-central Texas (Figure 1). The Barnett represents the grandfather of shale reservoirs where "shale as source rock" was first established, and where the necessary set of technologies, namely horizontal drilling and multi-stage fracturing, were developed to make hydrocarbon extraction economically feasible in shale.

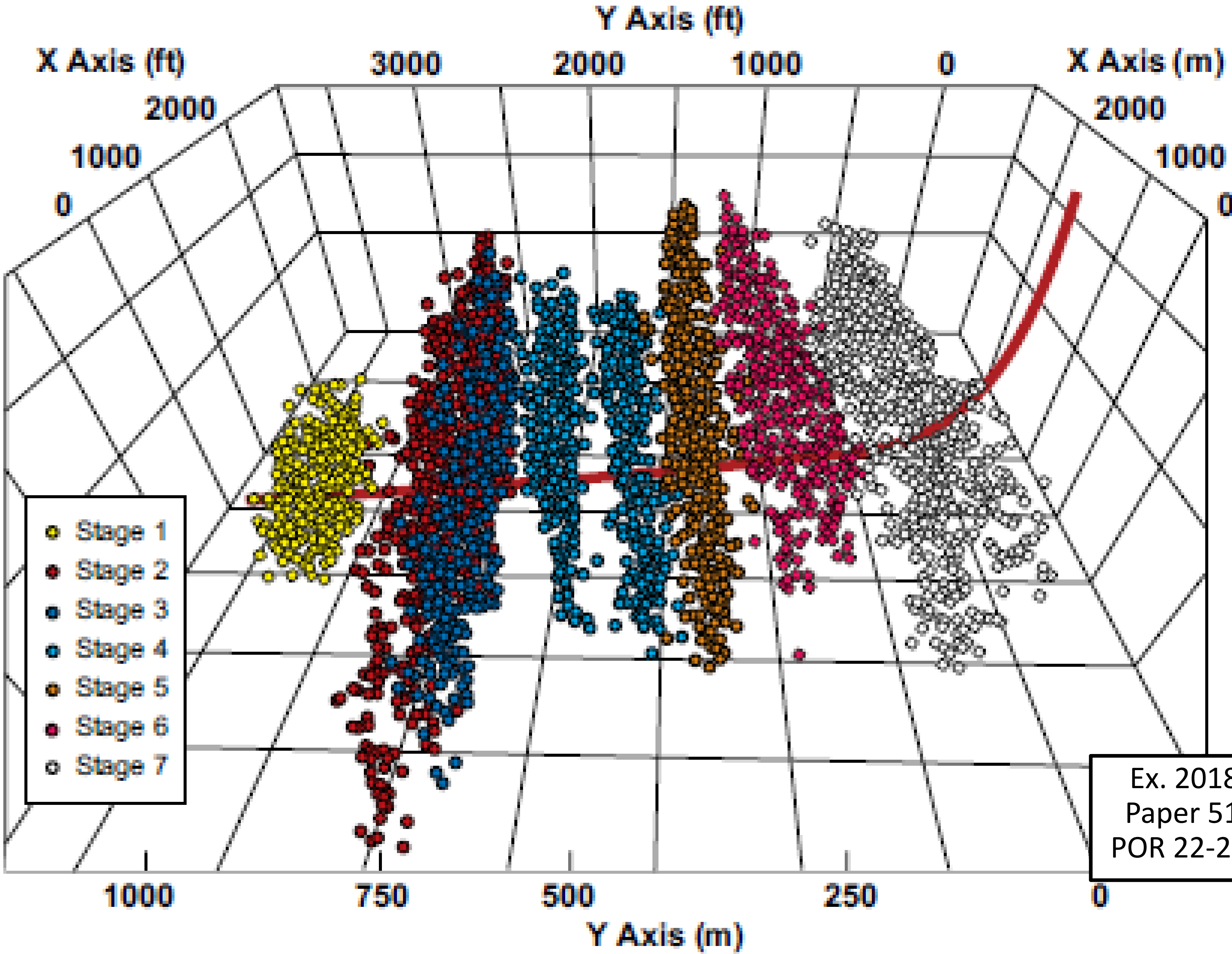
The Barnett is conformably overlain by the Pennsylvanian-age Marble Falls Limestone and unconformably overlies the Ordovician-age Viola Limestone/Ellenberger Group, which serves as a frac barrier (Figure 2) (Bowker, 2003; Pollastro et al., 2003). The core area of the Barnett is located in the Denton, Wise and Tarrant Counties where it is approximately 300 to 500 ft. thick with porosity and permeability values in the range of 3 – 5% and 0.00007 – 0.0005



	6 Month Cumulative MMCFGE	12 Month Cumulative MMCFGE	24 Month Cumulative MMCFGE	60 Month Cumulative MMCFGE
2004	165	281	451	781
2005	155	265	413	757
OHMS Wells	213	350	528	945

Figure 6. Summary of cumulative production data for OHMS and offset wells in Denton County.

Ex. 2018;
Paper 51,
POR 22-23



Ex. 2018;
Paper 51,
POR 22-23

“game-changing technology”

(Ex. 2033) “prize product”

(Ex. 2004)

“revolutionary technology”

(Ex. 2008)

(Ex. 2048)

EY Entrepreneur Of The Year™

(Ex. 2048)

“Multistage fracking pioneer…”

(Ex. 2006)

Packers Plus®
DO IT ONCE. DO IT RIGHT.

Sproule Achievement Award

(Ex. 2048)

“disruptive technology”

(Ex. 2046)

“legendary”

(Ex. 2046)

2014 TECH REV INNOVATORS

(Ex. 2048)

“… revolutionized the completions sector…”

(Ex. 2006)

“the industry standard”

(Ex. 2009)

Paper 51,
POR 26-31

LEADING THE WAY

Multistage fracking pioneer Packers Plus plays major role in cracking the tight oil code

WHEN THE HISTORY of all the business success stories emerging from the development of the tight oil and gas reservoirs in western Canada and the western United States is chronicled, the story of a 12-year-old Calgary-based company that specializes in an area of oilfield technology unheard of until the last few years might be the most remarkable.

"We started small," says Dan Themig, president of Packers Plus Energy Services Inc. "When we were starting to set up our offices, I brought a computer from my house and we bought office furniture at the Salvation Army."

A decade later, the privately owned company employs over 750 and has annual sales likely in the hundreds of millions of dollars—although Themig refuses to divulge revenue figures. He says dollar figures aren't important and serving customers is.

Packers Plus has built two state-of-the-art manufacturing centres and a Rapid Tool Development facility—specializing in engineering, research and development, and testing—in Edmonton. It also maintains a U.S. corporate office, a technology centre and a Rapid Tool Development facility in Houston. It has seven offices and/or facilities overall in Canada, 11 in the United States, and has offices worldwide, including in the Middle East, the North Sea region, China and Latin America, with 31 offices overall.

Themig says it's inevitable that it will double its workforce in the next few years.

Themig and partners Ken Paltzat and Peter Krabben, who had all worked together at the former Dresser Industries and then for Halliburton Energy Services Inc., which bought out that company, knew exactly what they wanted to do with the fledgling company when they left secure jobs and formed it.

"We were committed from day one to bringing technology to the land-based drilling industry, with a focus on horizontal completions," said Themig.

That focus led to the development of a number of completion technologies, starting with the StackFRAC system, which revolutionized the completions sector by introducing multistage fracturing systems in horizontal wells, credited with unlocking the potential of tight and shale oil and natural gas.

The firm has since introduced dozens of products, including the new QuickFRAC system in 2011, which allows for up to 60 stages downhole while pumping 15 treatments at surface.

"QuickFRAC is a great technology that can meet the need for increased stage numbers in formations such as the Bakken, Horn River and the Montney as well as many others," said Themig. "QuickFRAC allows the operator to do the job of pumping 15 stages on surface while Packers Plus does the job downhole, providing as many as 60 individual stages. This is done by taking a single pumping treatment on surface and precisely directing it into two to five stages downhole. For the operator, pumping time and costs are reduced significantly and production results are greatly increased."

Last summer it introduced its RepeaterPORT sleeve technology, which allows operators to increase the number of stages per lateral when they utilize existing Packers Plus systems.

"When we started the company we saw the need for high-end fracturing completions technology," said Themig. "There was horizontal drilling going on, but nobody was fracking."

The idea of starting a service firm that concentrated on a value-added niche came partially as a result of a class Themig took while he was studying towards a master's degree in business administration. "The professor said a business can either be a Saks Fifth Avenue or be a low-end alternative," he said. "We picked the Saks model."

Packers Plus first introduced its completions technology in the Barnett shale in 2003 and it now dominates the completions segment in most land-based tight and shale oil plays.

▲ **FASTER, GREENER** Capable of fracturing 60 stages downhole while only pumping 15 treatments at the surface, the Packers Plus QuickFRAC system also greatly reduces water usage by using consistent pumping rates.

"When we started you could do five fracs," he said. "Our StackFRAC brought that up to 20 and now we have technology that can do 60."

More recently it has moved into the offshore market. "Offshore reservoirs might have an extended production life of 20 years or so because of our technology," said Themig. "We don't think the market understands that potential yet."

It continues to be an engineering-focused company, with about 10 per cent of its employees having engineering or technology degrees. He said the company has dozens of engineering projects underway and a number of projects in the developing stages.

Themig said the firm will be introducing a range of new products over the next six to seven years. And it's expanding its manufacturing capacity for a good reason. "We can't keep up with demand," he said. ■

Jim Bentein

Exhibit 2006
IPR2016-00598

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Ex. 2006, Leading the Way: Multistage fracking pioneer Packers Plus plays major role in cracking the tight oil code, Canadian OilPatch Technology Guidebook (2012); Paper 51, POR at 26-31.

Packers Plus
Energy Serv

DAN THEM

IN JANUARY 2000, Dan Themig, Ken Paltzat and Peter Krabben abandoned the security of their jobs at oil-services giant Halliburton to start their own firm. Based in Calgary, Packers Plus Energy Services Inc. aimed to help the industry tackle the thorniest, hardest-to-reach deposits. When a client from Texas presented the upstart with one such challenge in 2001, Themig used his time on a flight to a meeting to sketch out the idea for what would become Packers' StackFrac system. The technology unlocks previously unviable deposits, maximizing production in mature oilfields and tight rock formations. Now, with the help of a partner — international oilfield giant Schlumberger — Packers is rapidly expanding overseas. Here, founding partner and president Dan Themig shares the story.

FINANCIAL POST MAGAZINE: What drew you to the oil-and-gas industry? You're a farm kid from southern Illinois — not exactly oil country.

DAN THEMIG: My dad worked for Unocal's pipeline division, but not in exploration. I didn't know much about the oil-and-gas business until I graduated with a civil engineering degree from the University of Illinois and got a job at Halliburton. I ended up in Texas for four years, then I talked my way into being transferred to Canada. I love to snowboard, ski, climb and whitewater-kayak, and they just don't have many mountains in Texas. Also, the Canadian oilfields are known for fostering small companies and innovation. Someone once told me that at an oil-and-gas conference in Europe, the first thing [a presenter] said was, "If the technology isn't born in Canada or Norway, it's probably not worth talking about."

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THEMIG: Working
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That was like puttin
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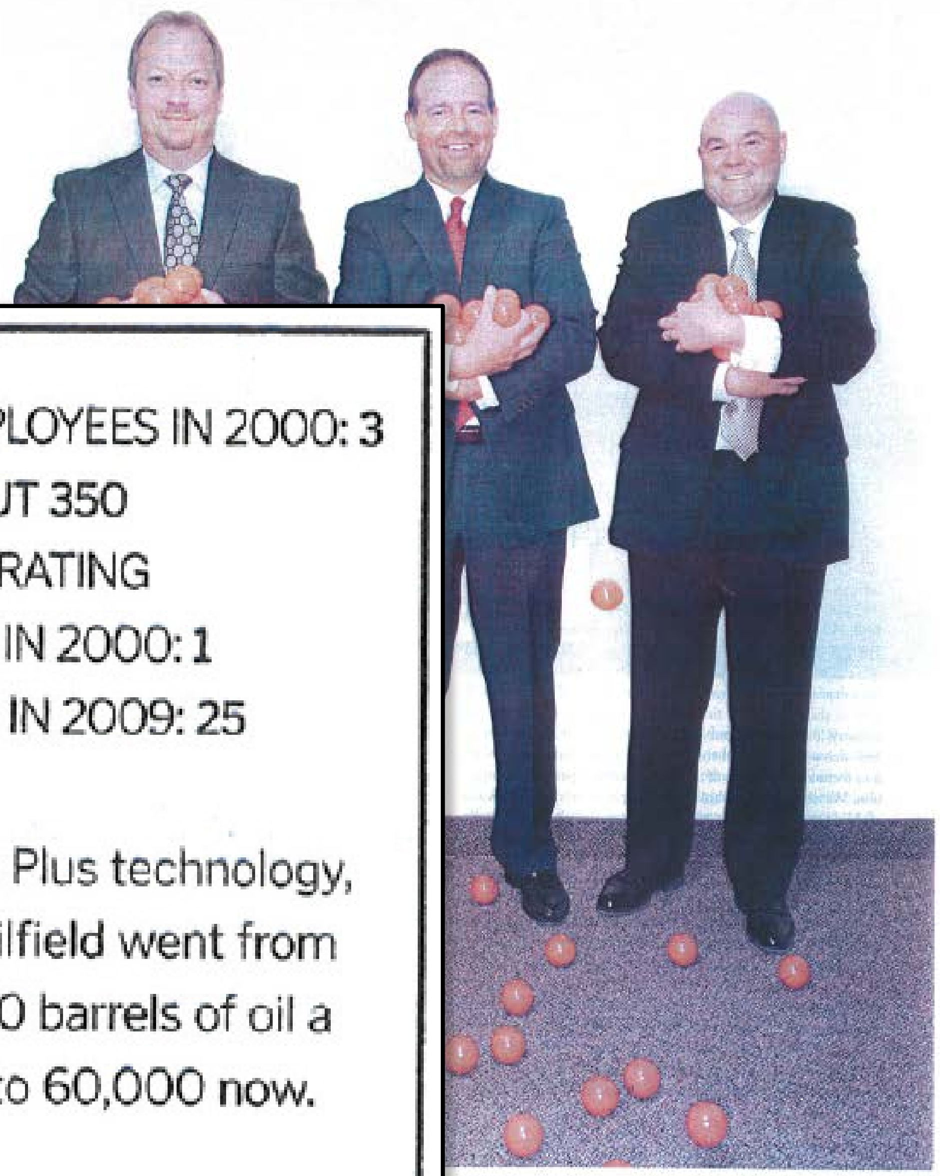
INTERVIEW BY JOANNA PA



> NO. OF EMPLOYEES IN 2000: 3
> 2009: ABOUT 350
> NO. OF OPERATING LOCATIONS IN 2000: 1
> LOCATIONS IN 2009: 25

With Packers Plus technology, the Bakken oilfield went from producing 100 barrels of oil a day in 2006 to 60,000 now.


EXPLORATION AND DEVELOPMENT

THE INNOVATION **STACKFRAC**
THE INNOVATOR **DAN THEMIG**

IF THERE WAS A HALL OF FAME FOR oil and gas industry innovators, Packers Plus president Dan Themig would be an inner-circle member. Along with Peter Krabben and Ken Paltzat, Themig founded Packers Plus, a company that would help revolutionize the way horizontal wells were fracked – and in turn help revolutionize the entire North American oil industry. StackFRAC, the company's prize product and primary innovation, is an open hole ball drop completion system that's widely credited with unlocking old resource plays that were thought to be too expensive or too technically challenging to tap. The company has continued to press ahead in the years since, adding new functions and features to its StackFRAC process along with additional tools and technologies. That, in turn, has allowed operators to dramatically increase the number of frack stages in each well – and the production that comes with them. In 2012, Themig was recognized for his work with a Sproule Innovation and Achievement Award, which are given to individuals or organizations that "have made significant contributions and accomplishments towards advancing the development of unconventional gas resources in Canada." It's a safe bet that it won't be the last award he receives for his contributions to that sector.

Exhibit 2005
IPR2016-00598

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Ex. 2005, Exploration and Development, Alberta Oil Magazine; Paper 51, POR at 26-31.

SPE 164009

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The OHMS completion system has in general been applied to carefully selected fields and has not yet gained wider acceptance, across the industry, as a viable alternative to the more popular and extensively utilised Plug and Perf approach. This resistance to change and the reluctance to consider alternative completion approaches, are due to a number of factors, many of which reflect an operational comfort zone from which there is a hesitancy to stray. Often the disadvantages of the OHMS approach may be overemphasized, while the associated advantages are not suitably considered and vice versa for the Plug and Perf approach.

Case histories from a number of North American unconventional plays, for example the Red Oak, the Cotton Valley and the Granite Wash, will be both presented and analyzed. This analysis will focus on a number of aspects, including the hydraulic fracturing treatments, the operational efficiencies, the cost effectiveness and the overall risk reduction aspects of the OHMS vs. the Plug and Perf approaches.

Introduction

Over the past decade, the Oil and Gas industry has considerably increased the well completion activity levels taking place across the unconventional plays within North America. Continued advancements in both the completions technologies and the operational techniques, particularly when combining horizontal drilling and hydraulic fracturing, have allowed an efficient access to previously uneconomic resources to be achieved. These previously uneconomic resources comprise of a number of different plays, consisting of various pore fluids, formation lithologies and hydrocarbon trapping mechanisms. In this respect, the tight gas-sands, coal bed methane (CBM), shale gas and more recently shale oil opportunities can all be considered a part of the unconventional resource grouping.

Fundamentally, the reasoning behind the consideration of horizontal well drilling is fairly simple, horizontal wells will provide an additional amount of contact area within the reservoir and by this means an improved production rate compared to a vertical well can be achieved. However, the reality is not as straightforward and the increased surface area, exposed to the reservoir, is not the only factor directly affecting this enhanced production rate.

In order to explain more clearly, consider the simple derivation of the Darcy flow equation for an ideal liquid, for a vertical well (1), written in oilfield units. This equation simply states that the production rate (q) is directly proportional to the applied drawdown (Δp), the reservoir thickness (h), the formation permeability (k), the wellbore radius (r_w) and is also inversely proportional to the pore-fluid viscosity (μ) and the fluid formation volume factor (B).

$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \qquad \ldots (1)$$

Exhibit 2001
IPR2016-00598

With the objectives of making multi stage horizontal well fracturing more efficient, both in terms of cost and time, the first commercial OHMS systems were developed and deployed in 2001 (Snyder 2011).

Ex. 2014 at 5, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013); Paper 51, POR at 26-31.

SPE 164009

Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics.

Alberto Casero, Hammed Adefashe, Kevin Phelan, BP America Inc.

This paper was prepared for presentation at the SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28–30 January 2013.

Abstract

During the past decade, the combination of hydraulic fracturing and horizontal wells, has proven to be the key, to the unlocking of unconventional plays across North America and elsewhere. This efficiency has been accomplished by using two very distinct completion approaches: the Plug and Perf. method and the Open Hole Multi Stage (OHMS) completion system (typically ball activated fracturing ports).

The OHMS completion system has in general been applied to carefully selected fields and has not yet gained wider acceptance, across the industry, as a viable alternative to the more popular and extensively utilised Plug and Perf approach. This resistance to change and the reluctance to consider alternative completion approaches, are due to a number of factors, many of which reflect an operational comfort zone from which there is a hesitancy to stray. Often the disadvantages of the OHMS approach may be overemphasized, while the associated advantages are not suitably considered and vice versa for the Plug and Perf approach.

Case histories from a number of North American unconventional plays, for example the Red Oak, the Cotton Valley and the Granite Wash, will be both presented and analyzed. This analysis will focus on a number of aspects, including the hydraulic fracturing treatments, the operational efficiencies, the cost effectiveness and the overall risk reduction aspects of the OHMS vs. the Plug and Perf approaches.

Introduction

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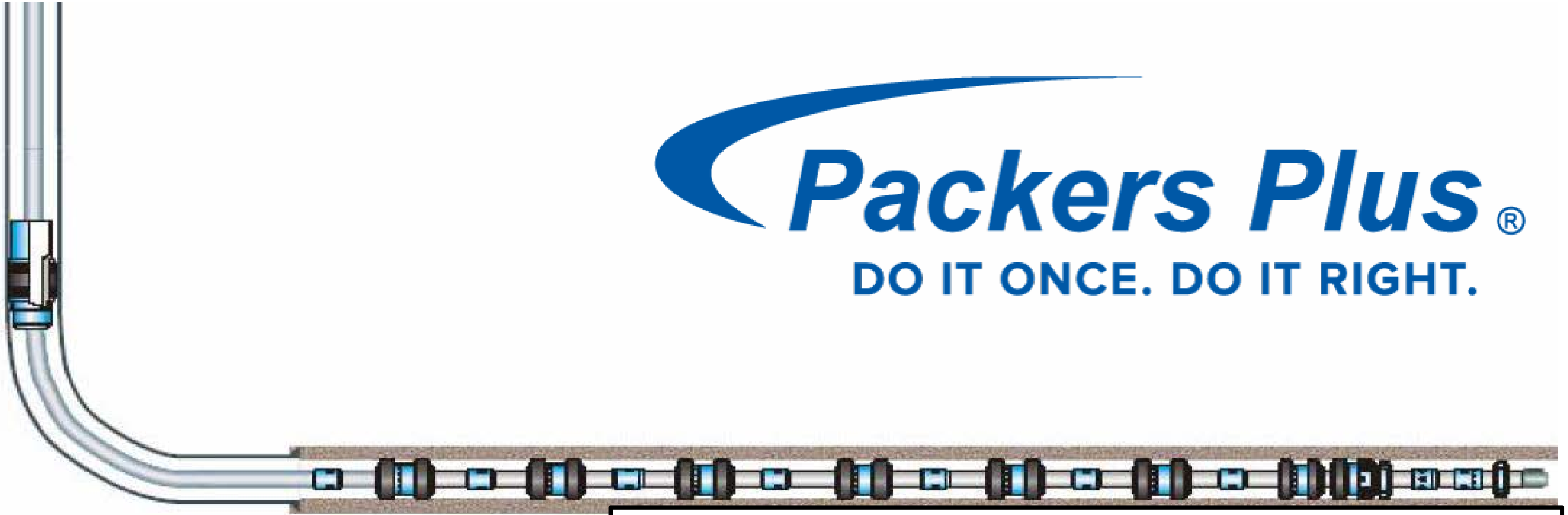
Fundamentally, the reasoning behind the consideration of horizontal well drilling is fairly simple, horizontal wells will provide an additional amount of contact area within the reservoir and by this means an improved production rate compared to a vertical well can be achieved. However, the reality is not as straightforward and the increased surface area, exposed to the reservoir, is not the only factor directly affecting this enhanced production rate.

In order to explain more clearly, consider the simple derivation of the Darcy flow equation for an ideal liquid, for a vertical well (1), written in oilfield units. This equation simply states that the production rate (q) is directly proportional to the applied drawdown (Δp), the reservoir thickness (h), the formation permeability (k), the wellbore radius (r_w) and is also inversely proportional to the pore-fluid viscosity (μ) and the fluid formation volume factor (B).

$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \qquad \ldots (1)$$

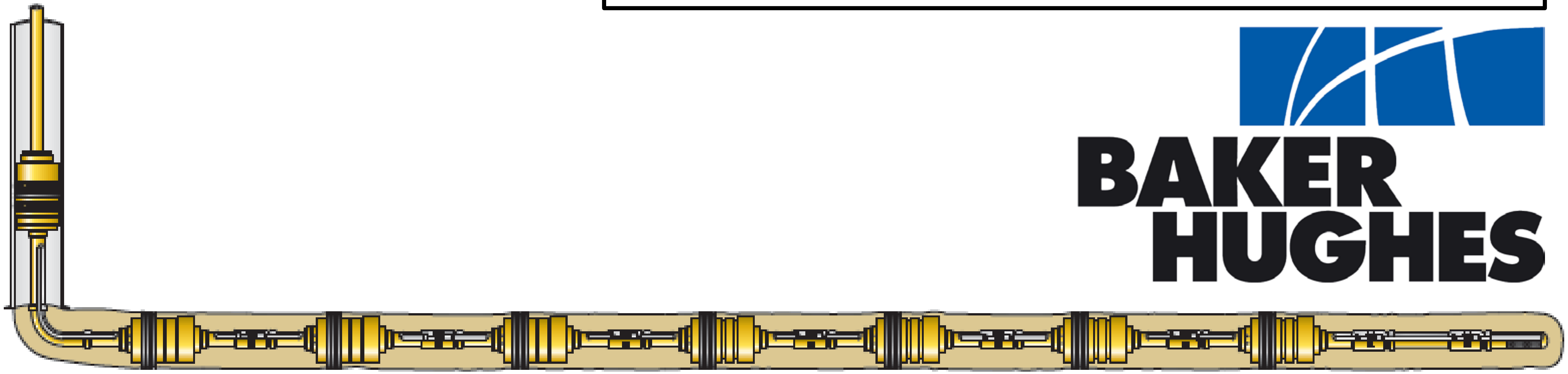
Currently, there are a number of commercial OHMS systems to choose from, but for the most part, these systems utilize similar principles.

Ex. 2014 at 4, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013); Paper 51, POR at 26-31.



Packers Plus®
DO IT ONCE. DO IT RIGHT.

Exs. 2004; 2018; 2053; 2056; 2057; 2058 (video); 2061 (video)



BAKER HUGHES

Exs. 2019; 2020; 2052; 2059 (video)

Q. Are you familiar with Baker Hughes' Fracpoint system?

A. Ditto what I told you about Packers Plus relative to Baker Hughes.

Q. That's another open-hole ball-drop system, right?

A. Yes. It's open.

Ex. 2017, A. Daneshy Depo. at 96:1-5

IsoFrac – Generation 1

- Generation 1
  - System Status (Testing and
    - Packer
      - Design Requirements – H
        in. open hole
      - Packer Testing Results – I
        able to achieve 10,000 psi
    - Frac Sleeve
      - Design Requirements – R
      - Ball Testing Time Line and
    - Equipment Delivery
      - Status of Equipment
    - System Issues

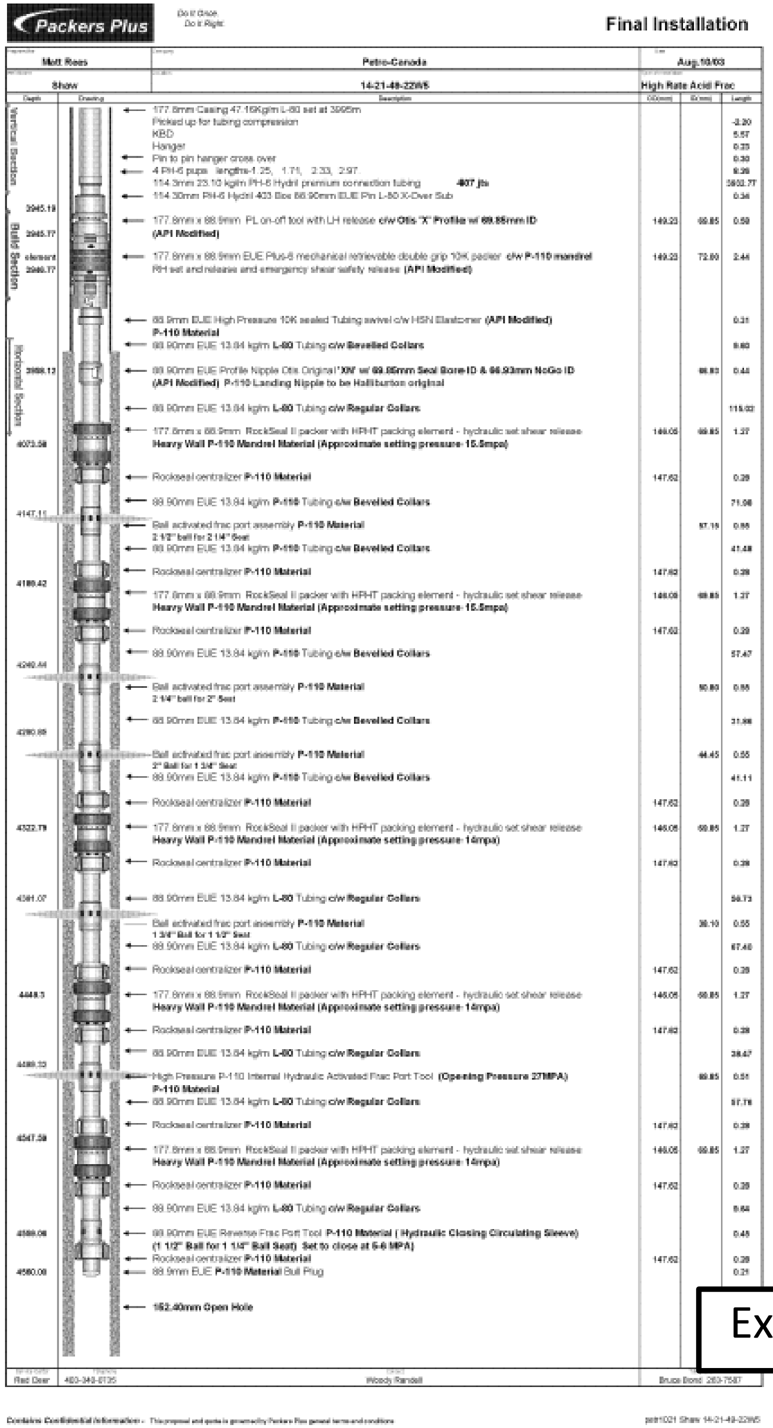
BAKER HUGHES Baker Oil Tools

Market Drivers & Opportunities

- Competition:
  - Packers Plus
    - Proven System
- Opportunities
  - Mid Con
    - Generation 1 and Generation 2
      - 6 1/4" Open Hole, 8,500PSI, &250F
  - MALT
    - Generation 3
      - 6 ¼" Open Hole, 10,000PSI, & 375F

BAKER HUGHES Baker Oil Tools

Ex. 2052 at 25-26



Packers Plus Do it Once. Do it Right.

Final Installation

Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-48-22W5	High Rate Acid Frac

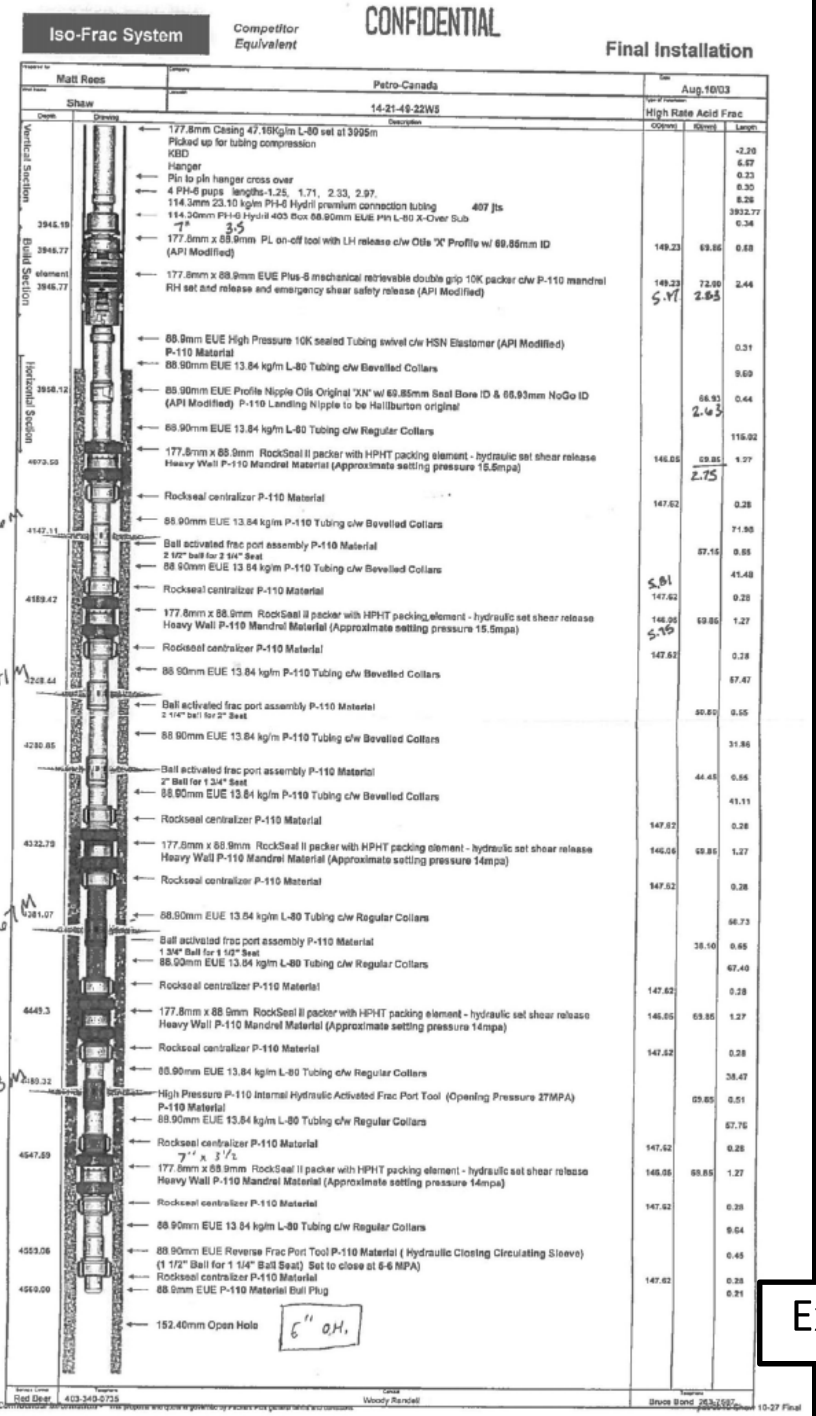
Depth	Description	OD(mm)	ID(mm)	Length
	177.8mm Casing 47.16Kg/m L-80 set at 3995m			
	Picked up for tubing compression			-2.20
	KBD			5.57
	Hanger			0.23
	Pin to pin hanger cross over			0.30
	4 PH-6 pups lengths-1.25, 1.71, 2.33, 2.97.			8.26
	114.3mm 23.10 kg/m PH-6 Hydril premium connection tubing **407 jts**			3932.77
	114.30mm PH-6 Hydril 403 Box 88.90mm EUE Pin L-80 X-Over Sub			0.34
3945.19				
3945.77	177.8mm x 88.9mm PL on-off tool with LH release **c/w Otis "X" Profile w/ 69.85mm ID (API Modified)**	149.23	69.85	0.58
element 3946.77	177.8mm x 88.9mm EUE Plus-6 mechanical retrievable double grip 10K packer **c/w P-110 mandrel** RH set and release and emergency shear safety release **(API Modified)**	149.23	72.00	2.44
	88.9mm EUE High Pressure 10K sealed Tubing swivel c/w HSN Elastomer **(API Modified) P-110 Material**			0.31
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Bevelled Collars**			9.60
3958.12	88.90mm EUE Profile Nipple Otis Original **"XN" w/ 69.85mm Seal Bore ID & 66.93mm NoGo ID (API Modified) P-110 Landing Nipple to be Halliburton original**		66.93	0.44
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			115.02
4073.58	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release **Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)**	146.05	69.85	1.27
	Rockseal centralizer **P-110 Material**	147.62		0.28
	88.90mm EUE 13.84 kg/m **P-110** Tubing **c/w Bevelled Collars**			71.98
4147.11	Ball activated frac port assembly **P-110 Material** 2 1/2" ball for 2 1/4" Seat		57.15	0.55
	88.90mm EUE 13.84 kg/m **P-110** Tubing **c/w Bevelled Collars**			41.48
	Rockseal centralizer **P-110 Material**	147.62		0.28
4189.42	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release **Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)**	146.05	69.85	1.27
	Rockseal centralizer **P-110 Material**	147.62		0.28
	88.90mm EUE 13.84 kg/m **P-110** Tubing **c/w Bevelled Collars**			57.47
4240.44	Ball activated frac port assembly **P-110 Material** 2 1/4" ball for 2" Seat		50.80	0.55
	88.90mm EUE 13.84 kg/m **P-110** Tubing **c/w Bevelled Collars**			31.86
4280.85	Ball activated frac port assembly **P-110 Material** 2" Ball for 1 3/4" Seat		44.45	0.55
	88.90mm EUE 13.84 kg/m **P-110** Tubing **c/w Bevelled Collars**			41.11
	Rockseal centralizer **P-110 Material**	147.62		0.28
4322.79	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release **Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)**	146.05	69.85	1.27
	Rockseal centralizer **P-110 Material**	147.62		0.28
4381.07	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			56.73
	Ball activated frac port assembly **P-110 Material** 1 3/4" Ball for 1 1/2" Seat		38.10	0.55
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			67.40
	Rockseal centralizer **P-110 Material**	147.62		0.28
4448.3	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release **Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)**	146.05	69.85	1.27
	Rockseal centralizer **P-110 Material**	147.62		0.28
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			38.47
4480.32	High Pressure P-110 Internal Hydraulic Activated Frac Port Tool **(Opening Pressure 27MPA) P-110 Material**		69.85	0.51
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			57.76
	Rockseal centralizer **P-110 Material**	147.62		0.28
4547.59	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release **Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)**	146.05	69.85	1.27
	Rockseal centralizer **P-110 Material**	147.62		0.28
	88.90mm EUE 13.84 kg/m **L-80** Tubing **c/w Regular Collars**			9.64
4559.06	88.90mm EUE Reverse Frac Port Tool **P-110 Material (Hydraulic Closing Circulating Sleeve) (1 1/2" Ball for 1 1/4" Ball Seat) Set to close at 5-6 MPA)**			0.45
	Rockseal centralizer **P-110 Material**	147.62		0.28
4560.00	88.9mm EUE **P-110 Material** Bull Plug			0.21
	152.40mm Open Hole			

Red Deer	403-340-0735	Woody Randell	Bruce Bond 263-7587

Contains Confidential Information - This proposal and quote is governed by Packers Plus general terms and conditions

pstr1021 Shaw 14-21-48-22W5

Ex. 2053



Iso-Frac System Competitor Equivalent

CONFIDENTIAL

Final Installation

Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-48-22W5	High Rate Acid Frac

Depth	Description	OD(mm)	ID(mm)	Length
	177.8mm Casing 47.16Kg/m L-80 set at 3995m			
	Picked up for tubing compression			-2.20
	KBD			5.57
	Hanger			0.23
	Pin to pin hanger cross over			0.30
	4 PH-6 pups lengths-1.25, 1.71, 2.33, 2.97.			8.26
	114.3mm 23.10 kg/m PH-6 Hydril premium connection tubing 407 jts			3932.77
	114.30mm PH-6 Hydril 403 Box 88.90mm EUE Pin L-80 X-Over Sub			0.34
3945.19	7" 3.5			
3945.77	177.8mm x 88.9mm PL on-off tool with LH release c/w Otis "X" Profile w/ 69.85mm ID (API Modified)	149.23	69.86	0.58
element 3946.77	177.8mm x 88.9mm EUE Plus-6 mechanical retrievable double grip 10K packer c/w P-110 mandrel RH set and release and emergency shear safety release (API Modified)	149.23 5.87	72.00 2.83	2.44
	88.9mm EUE High Pressure 10K sealed Tubing swivel c/w HSN Elastomer (API Modified) P-110 Material			0.31
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Bevelled Collars			9.60
3958.12	88.90mm EUE Profile Nipple Otis Original "XN" w/ 69.85mm Seal Bore ID & 66.93mm NoGo ID (API Modified) P-110 Landing Nipple to be Halliburton original		66.93 2.63	0.44
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			115.02
4073.58	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)	146.05	69.85 2.75	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			71.98
116M 4147.11	Ball activated frac port assembly P-110 Material 2 1/2" ball for 2 1/4" Seat		57.15	0.55
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			41.48
	Rockseal centralizer P-110 Material	5.81 147.62		0.28
4189.42	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)	146.05 5.75	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			57.47
91M 4240.44	Ball activated frac port assembly P-110 Material 2 1/4" ball for 2" Seat		50.80	0.55
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			31.86
4280.85	Ball activated frac port assembly P-110 Material 2" Ball for 1 3/4" Seat		44.45	0.55
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			41.11
	Rockseal centralizer P-110 Material	147.62		0.28
4322.79	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)	146.05	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
167M 4381.07	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			56.73
	Ball activated frac port assembly P-110 Material 1 3/4" Ball for 1 1/2" Seat		38.10	0.55
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			67.40
	Rockseal centralizer P-110 Material	147.62		0.28
4449.3	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)	146.05	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			38.47
98M 4480.32	High Pressure P-110 Internal Hydraulic Activated Frac Port Tool (Opening Pressure 27MPA) P-110 Material		69.85	0.51
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			57.76
	Rockseal centralizer P-110 Material	147.62		0.28
4547.59	7" x 3 1/2 177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 14mpa)	146.05	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Collars			9.64
4559.06	88.90mm EUE Reverse Frac Port Tool P-110 Material (Hydraulic Closing Circulating Sleeve) (1 1/2" Ball for 1 1/4" Ball Seat) Set to close at 5-6 MPA)			0.45
	Rockseal centralizer P-110 Material	147.62		0.28
4560.00	88.9mm EUE P-110 Material Bull Plug			0.21
	152.40mm Open Hole 6" O.H.			

Red Deer	403-340-0735	Woody Randell	Bruce Bond 263-7587

Contains Confidential Information

10-27 Final

Ex. 2052

Packers Plus *Do It Once. Do It Right.*

Final Installation

Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-49-22	

Depth	Description	OD(mm)	ID(mm)	Length
	177.8mm Casing 47.16Kg/m L-80 set at 3995m			
	Picked up for tubing compression			-2.20
	KBD			5.57
	Hanger			0.23
	Pin to pin hanger cross over			0.30
	4 PH-6 pups lengths-1.25, 1.71, 2.33, 2.97			8.26
	114.3mm 23.10 kg/m PH-6 Hydril premium connection tubi			3932.77
	114.30mm PH-6 Hydril 403 Box 88.90mm EUE Pin L-80 X-			0.34
	177.8mm x 88.9mm PL on-off tool with LH release c/w Oti (API Modified)	149.23	69.85	0.58
	177.8mm x 88.9mm EUE Plus-6 mechanical retrievable dou RH set and release and emergency shear safety release (A			2.44
	88.9mm EUE High Pressure 10K sealed Tubing swivel c/w P-110 Material			0.31
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Bevelled Colla			9.60
	88.90mm EUE Profile Nipple Otis Original 'XN' w/ 69.85mm (API Modified) P-110 Landing Nipple to be Halliburton c			0.44
	88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Colla			15.02
	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)	146.05	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			71.98
4147	177.8mm x 88.9mm RockSeal II packer with HPHT packing element -			
	Rockseal centralizer P-110 Material	147.62		0.28
4189.42	177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)	146.05	69.85	1.27
	Rockseal centralizer P-110 Material	147.62		0.28
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			57.47
4248.44	Ball activated frac port assembly P-110 Material 2 1/4" ball for 2" Seat		50.80	0.55
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			31.86
4280.85	Ball activated frac port assembly P-110 Material 2" Ball for 1 3/4" Seat			
	88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars			
	Rockseal centralizer P-110 Material	147.6		
4322.79	177.8mm x ... Heavy Wal... c set shear release	146.05	69.85	1.27
	Rockseal c...	147.62		0.28

Horizontal Section

152.40mm Open Hole

Ex. 2053

Iso-Frac System *Competitor Equivalent*

CONFIDENTIAL

Final Installation

Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-49-2	

High Rate Acid Frac

OD(mm)	ID(mm)	Length
		-2.20
		5.57
		0.23
		0.30
		8.26
		3932.77
		0.34
149.23	69.85	0.58

Horizontal Section

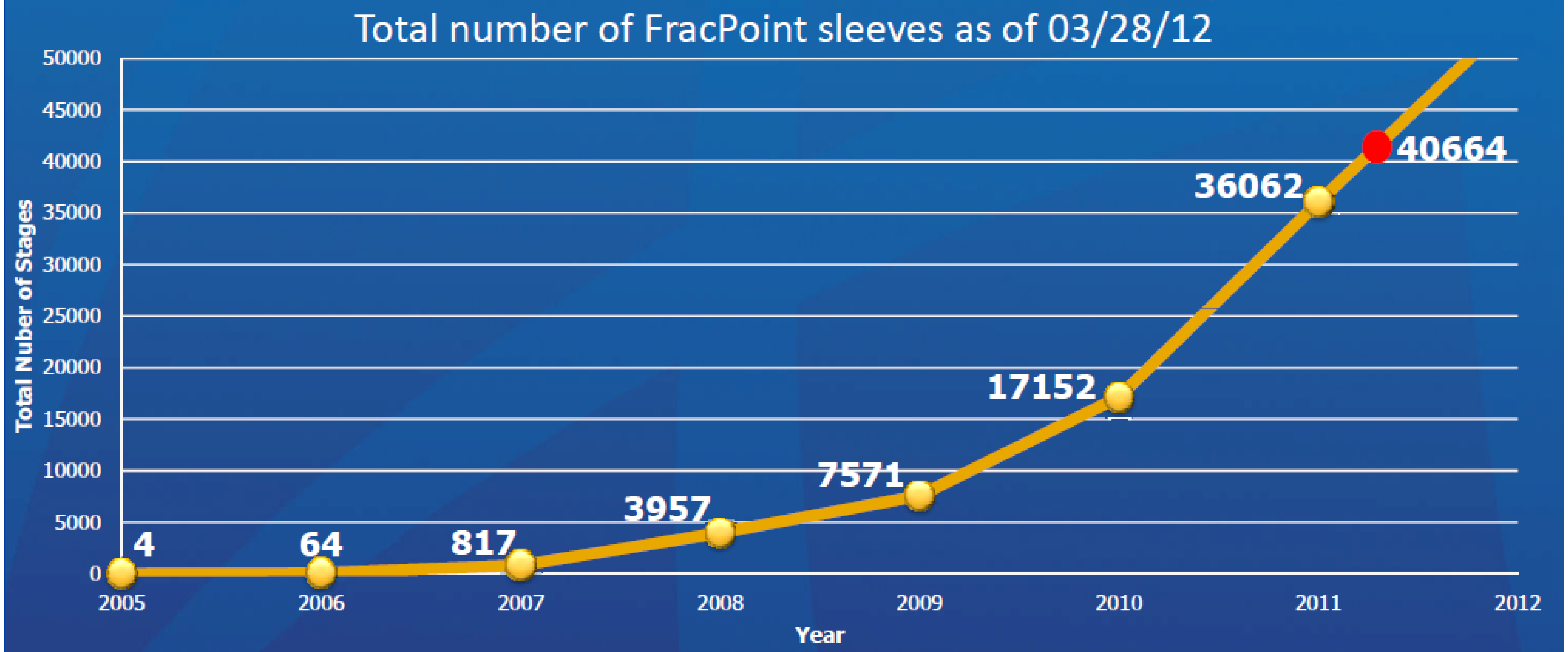
177.8mm x 88.9mm RockSeal II packer with HPHT packing element

7" 3.5 2.75 5.81 5.75

152.40mm Open Hole

Ex. 2052

FracPoint Experience in North America



- Installed in more than 35 formations by 117 Oil & Gas Operators
- Trends – Increased number of stages per system
- >2400 Wells-38,000 Packers-40,000 Sleeves

Ex. 2019 at 6

Paper 51, POR at 39-41

Plug & Perf Experience in North America

Total number of Composite Plugs as of 6/1/12

Ex. 2019 at 5

Paper 51, POR at 39-41

Since it was founded in 2000, Packers Plus has grown from a company of only a handful of individuals generating less than a million dollars in revenue to, at its height, employing more than 900 employees around the globe and generating [redacted] in annual U.S. revenue. The StackFRAC system has been critical to that success. Since StackFRAC was first introduced, Packers Plus has sold tools for or performed fracture treatments for tens of thousands of StackFRAC stages in the United States. That work accounts for the vast majority of Packers Plus' overall revenue and profits.

Ex. 2048, J.J. Giraldi Declaration

Qittitut Consulting

Openhole Multistage vs Plug-n-Perf Completion

Sleeves vs Shots—The Debate Ra

by Richard G. Ghiselin, P.E.

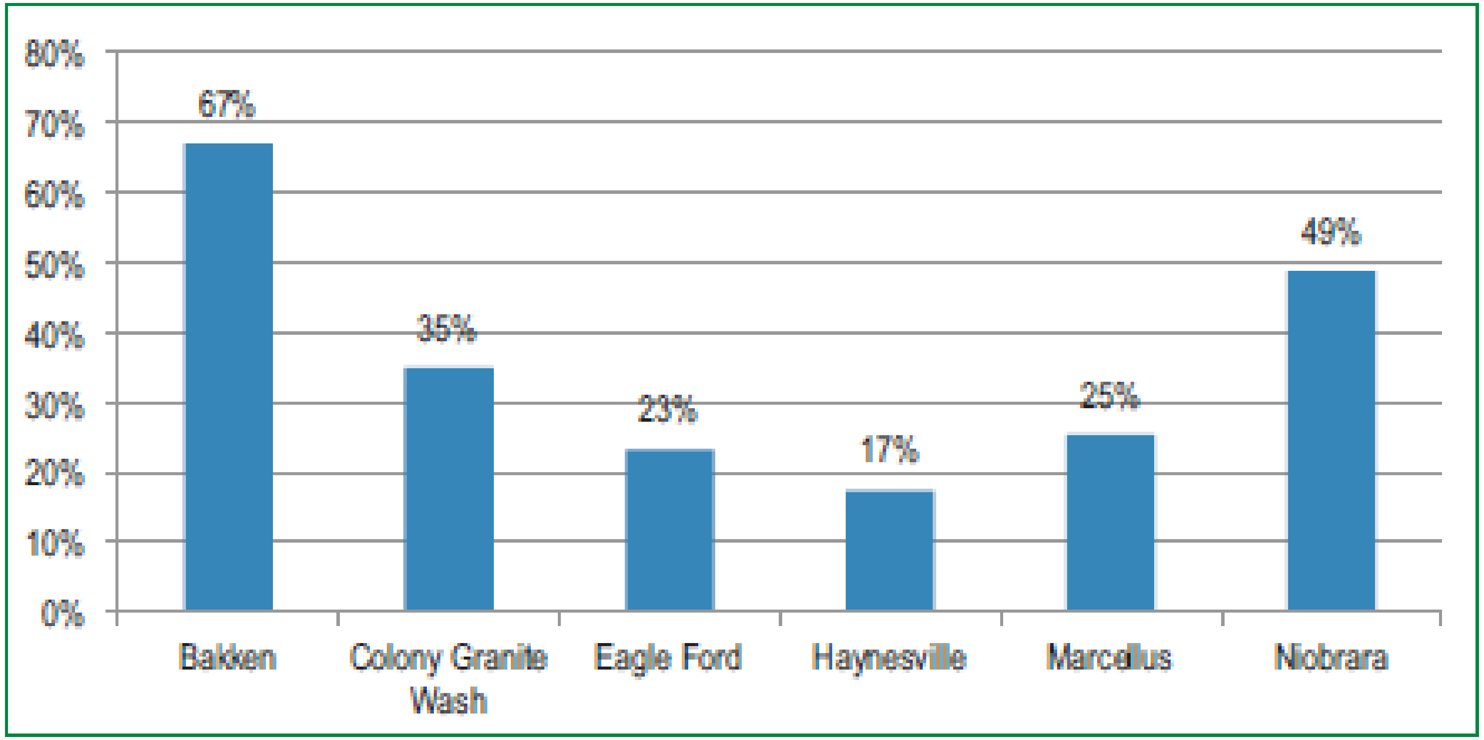


Figure 1. The OHMS technique for frac treatments is used in the Bakken play more than in other plays.

Exhibit 2011
IPR2016-00598

Ex. 2011 at 4

Paper 51, POR at 39-41

SPE-171183-MS

Single-Size-Ball Interventionless Multi-Stage Stimulation System Improves Stimulated Reservoir Volume and Eliminates Milling Requirements: Case Studies

Feng Yuan, Eric Blanton, and Jamie Inglesfield, Weatherford

This paper was prepared for presentation at the SPE Russian Oil and Gas Exploration and Production Technical Conference and Exhibition held in Moscow, Russia, 14–16 October 2014.

Abstract

In the last decade, there has been a tremendous growth in multi-stage fracturing for unconventional plays employing stimulation sleeves with open hole (OH) packers or cementing. Standard ball-activated frac sleeve systems with graduated ball seats have primarily been used because they can significantly save completion time and cost by facilitating the performance of multiple stimulations in a single continuous process compared with the conventional Plug and Perforate (P-n-P). However, traditional ball-activated frac sleeves have limitations in the number of stages that can be handled, the pressure drop and friction loss each one creates and the need to mill through the ball seats after stimulation. As the number of frac stages increases, the ball seat sizes become dramatically smaller leading to large increases in the surface treating pressure and hydraulic horse power (HHP) needed to generate a given net downhole pressure or injection rate.

To solve these limitations a revolutionary ball-activated fracturing system has been designed. This system behaves in similar fashion of activation to the traditional graduated ball seat frac sleeve in that the ball locks into place on the seat, but all the ball seats are the same size and retract, allowing the first ball to pass through all sleeves until it reaches the lowermost one. Similarly the next ball, which is the same size, lands on the next seat up and so on, allowing a virtually unlimited number of zones to be treated for either OH or cemented application. With this new system, there is no milling operation involved and the completion string maintains full drift inside diameter (ID) ready for production after stimulation operations have been completed.

In this paper the authors will describe in detail the operational mechanism of this new frac sleeve and present case studies of its use which illustrates the effect of this new technology in optimizing fracturing operations both in horsepower requirements and overall completion time and cost.

Introduction

There is a lot of debate about how best to complete and fracture unconventional formations regarding the effectiveness and efficiency differences between frac sleeve and P-n-P methods. Generally speaking, P-n-P is a time-consuming frac technique, due to the need for running Tubing Conveyed Perforating

Ex. 2074
IPR2016-01509

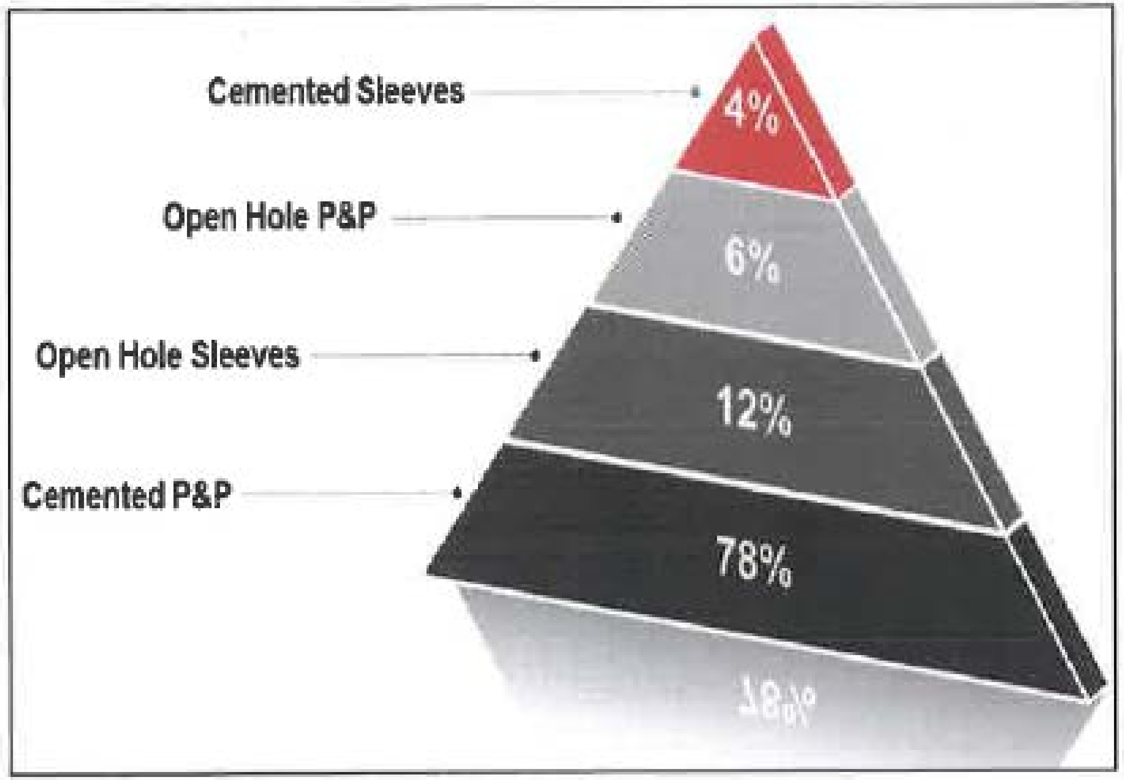


Figure 1—Percentages for different frac methods at Weatherford.

Figure 1 shows the distribution in percentages for different frac methods used in operations performed by Weatherford which reflect closely the overall distribution throughout the industry.

Ex. 2074 at 2

Paper 51, POR at 39-41

Lane-Wells

Other common additives are sequestering agents, which prevent precipitation of ferric iron during acidizing, and *antisludge agents*, which prevent an acid from reacting with certain types of crude and forming an insoluble sludge that blocks channels or reduces permeability.

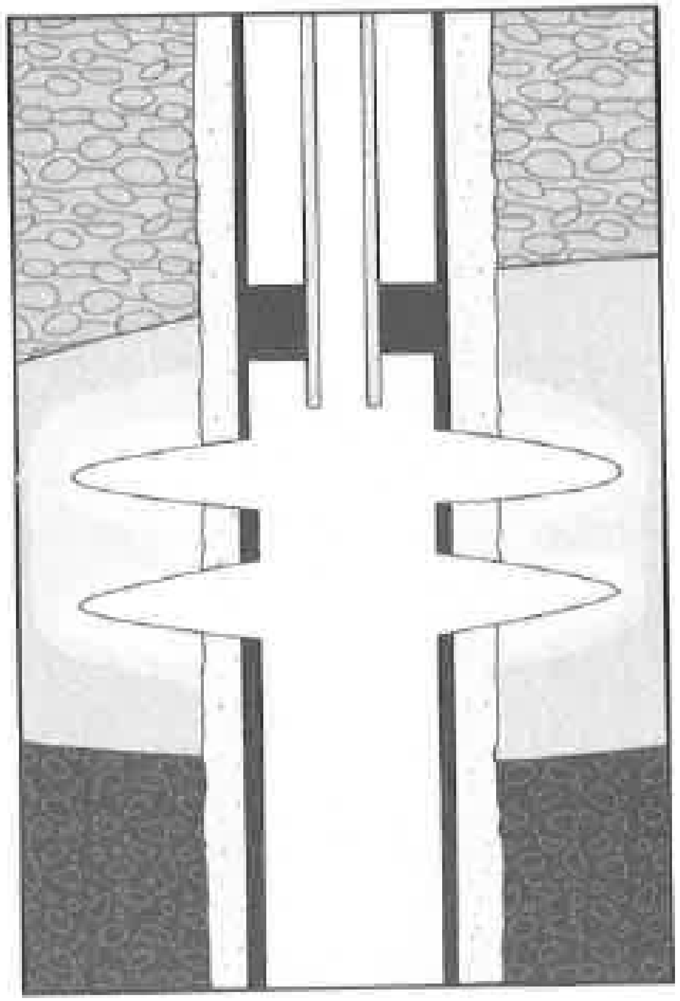


Figure 5.29 Acid is injected down the tubing and into the formation through perforations to remove formation damage without fracturing the formation.

Types of Acidizing Treatments

There are two basic kinds of acid stimulation treatments: acid fracturing and matrix acidizing.

Acid fracturing, or *fracture acidizing*, is similar to hydraulic fracturing, with acid as the fluid. Acid fracturing does not require proppants, however, because it does not just force the rock apart, but also eats it away. It is the more widely used treatment for well stimulation with acid. Since most limestone and dolomite formations have very low permeabilities, injecting acid into these formations, even at a moderate pumping rate, usually results in fracturing.

Matrix acidizing can be subdivided into two types. The first is *wellbore cleanup*, or *wellbore soak*. In wellbore soak, the crew fills up the wellbore with acid without any pressure and allows it to react merely by soaking. It is a relatively slow process because little acid actually comes in contact with the formation. The second matrix acidizing method is a low-pressure treatment that does not fracture the formation, but allows the acid to work through the natural pores (fig. 5.29). This second process is what people in the oil patch are usually referring to when they speak of matrix acidizing. Operators generally use matrix acidizing when the formation is damaged or when a water zone or gas cap is nearby and fracturing might result in excessive water or gas production.

Ex. 1006 at 4

If the operator exceeds the fracture gradient and fractures the formation, the acid will be forced into the fracture where it is quickly transferred away from the wellbore and spends on the face of the fracture. This would defeat the purpose of the matrix acidizing, which is to cause acid to remove reservoir damage in the formation near the wellbore (the “near-field”)

Ex. 2081, McGowen Dec. at 12

2854

LANE-WELLS
Packers

Engineered PACKER SERVICE

LANE-WELLS TUBING PORT VALVE

The Lane-Wells Tubing Port Valve is used primarily to displace fluids in the annulus above a packer. When formation pressures are such that heavy fluids in the well cannot be displaced prior to setting a packer, the installation of the Tubing Port Valve is needed. After Tubing Port Valve is placed in tubing string above packer and run in, the packer is set and the well head closed in. With the well secure, a ball is dropped through the tubing to seat in the Tubing Port Valve. Flow through tubing is stopped and pump pressure build-up causes spring to compress which opens side ports. This "inside out" circulation allows safe displacement of fluids in the annulus.

The Tubing Port Valve also provides a means of acidizing two zones with packer setting in either open-hole or cased hole completion. Three zone acidizing is possible with a three packer set-up and two different sized Tubing Port Valves.

Pressure Maintenance or Storage.

Features:

Departure from standard Lane-Wells Design principles to permit hookwall action in limited space.

For detailed discussion of any of these applications call your nearest Lane-Wells branch or write to the Lane-Wells Company, P. O. Box 2194, Los Angeles 54, Calif.

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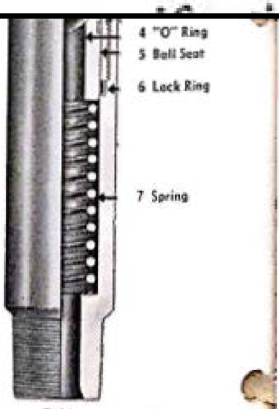
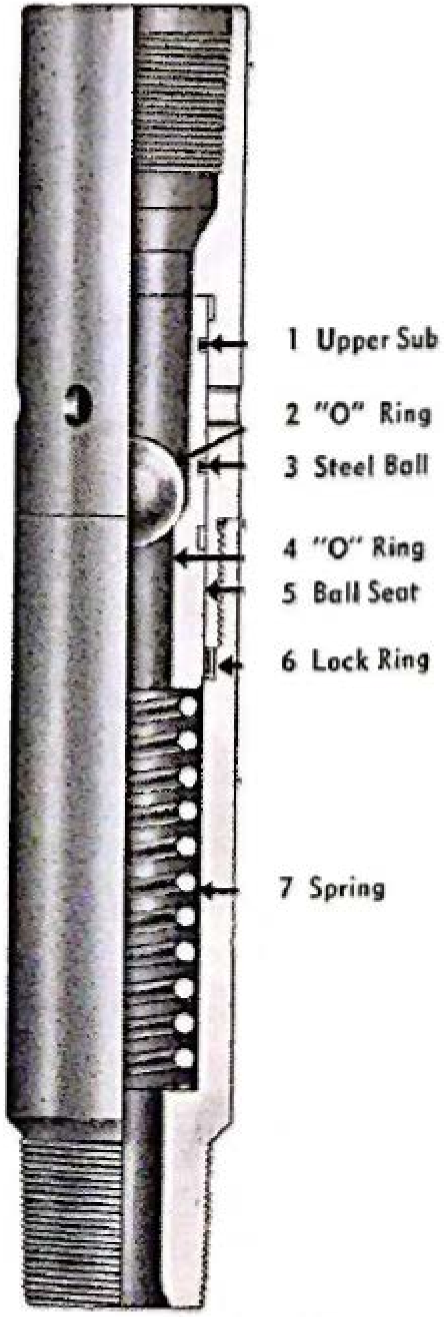


Tubing Port Valve



Tubing Port Valve

LANE-WELLS
Packers

SERIES 3 & 4 FORMATION PACKERS
(Sleeve Packing Element)
(Series 4 is Valve Anchor Type)

Series 4

Lane-Wells Series 3 Packers are used in the following applications to obtain a positive open-hole-to-tubing pack-off where very low fluid heads prevail and a by-pass or valve to circulate above packer is not required:

Lane-Wells Series 4 Packers are used in the following applications to obtain a positive pack-off between open hole and tubing or drill pipe in fluid-laden wells. The by-pass makes possible easy running and pulling through fluid, and the circulating valve permits changing fluids, equalization of pressures and removal of settings by circulation.

For:

- Improving Natural Flow Efficiency
- Improving Gas-Oil Ratios
- Packing-off Water
- Protecting Casing
- Testing Formation Content, Single Zone
- Acidizing, Single Zone
- Inducing Tubing Flow with Side Door Chokes, Tubing Perforations or Gas Lift Valves
- Improving Volumetric Efficiency of Plunger Pumps, Separating Zones, Reducing Heading, etc., in Pumping Wells

For detailed and helpful discussion of packer applications call your nearest Lane-Wells Branch.

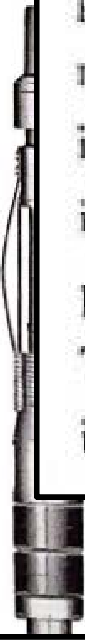
TOP

Where below packer pressures and/or lack of tubing weight make it impractical to use a conventional packer, Lane-Wells Tension Operated Packers best meet the requirement. The slips are set and the packing rings expanded by pulling tension on the tubing instead of applying weight on top of the packer. This packer is excellent in formation fracturing operations. The TOP is especially recommended for water flood injection.

HYDRAULIC HOLD DOWN TOOL

For additional resistance to vertical movement of a packer when extremely high below packer pressures are anticipated, the Hydraulic Hold Down available. This tool holds over 6,000 psi diff has non-porous nickel plated pistons and bo vidual and specific holding points on the afford a positive fix in the casing and is ec because of its simplicity of design. The tool entirely by hydraulic pressures built up in the at the rear of the piston forcing the pistons contact in the casing. The greater the pressure trying to move the packer in the casing, the greater the pressure on the pistons and resultant holding action.

Hydraulic Hold Down



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Ex. 1002 at 16.

Both the TOP and the Hydraulic Hold Down Tool are specifically designed for use inside casing as their pressure rating and performance depend upon affixing the packer to the casing wall using slips and/or pistons that contact the casing wall.

Ex. 2081, McGowen Dec. at 9

Ask your LANE-WELLS *Man!*

LANE-WELLS Packers

Hookwall Type Packer

PACKER TYPES

There are two main classes of packers:

1. HOOKWALL PACKERS—supported by slips gripping the wall of the casing. These slips resist downward movement and when weight is applied, the packing element expands until packer is set.

2. ANCHOR PACKERS—supported by a tail pipe resting on bottom or connecting with another type packer set below. This anchor setting prevents downward movement of the packer when pressure is applied, and allows expansion of the packing assembly until packer is set.

ENGINEERED PACKER SERVICE

Engineered Packer Service is available to any operator, at his request, with no fee, cost, or obligation. This service insures the operator of correct procedures and applications to any problem confronted in packer operation. Ask your Lane-Wells man for further information.

Anchor Type Packer

INFORMATION REQUESTED WHEN ORDERING

HOW TO ORDER

We can serve you better if you supply all the information requested below at the time you send an inquiry or order.

Packers

Specifications covering Packers should show:

1. Type and Number of Packer (AO-1, etc.). No number needed for CO and SD.
2. Size and weight per foot (or I.D.) of casing in which packer is to be set (as 5½"—17 lbs.).
3. I.D. of mandrel required (as 2"). Write for Packer Bulletin for available diameters in each packer size.
4. Size, weight and thread of casing, tubing, drill pipe or tool joint on which packer is to be run. Always specify tubing as non-upset or external upset (E.U.E.). Tubing thread connection will be furnished A.P.I. 8 Round Thread E.U.E. unless otherwise ordered. On Formation Packer order, specify I.D. of casing packer is to run through and diameter of open hole in which packer is to be set.

General

All Packers can be furnished in drillable material, or with anti-corrosion coating, at extra cost.

All prices, dimensions, specifications, and weights of materials are subject to change without notice.

Special designs of packers will be built to order as "Custom" items. Quotations on such items will be prepared on request.

Destination

To comply with Department of Commerce regulations, it is necessary that all inquiries and orders for export state final destination.

Tubing Size

A.P.I. Standard Nomenclature lists tubing according to Actual O.D. instead of Nominal I.D. as formerly used. Data Tables in this catalog follow A.P. designations.

Prices

Current Packer Price Lists are available on request from all Lane-Wells offices.

Spare Parts

A pamphlet titled "Packer Parts Lists and Interchangeability Tables" is available on request. This information is especially useful to customers outside the United States and others concerned with large orders of parts.

Packer Availability

Popular types and sizes of Lane-Wells Packers available in stock at Lane-Wells Branch locations.

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downward movement of the packer when pressure is applied, and allows expansion of the packing assembly until packer is set.

Ex. 1002 at 12.

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Packers

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- Protecting Casing
- Testing Formation Content, Single Zone
- Acidizing, Single Zone
- Inducing Tubing Flow with Side Door Chokes, Tubing Perforations or Gas Lift Valves
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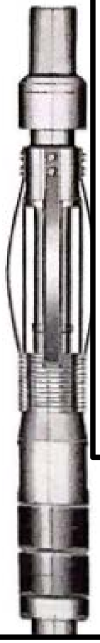
Hydraulic Hold Down



For:

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Protecting Casing
Testing Formation Content, Single Zone
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Improving Volumetric Efficiency of Plunger Pumps, Separating Zones, Reducing Heading, etc., in Pumping Wells

Ex. 1002 at 16.

[A] POSITA would know that the term "Acidizing" in the context of this 1955 reference does not equate to "Fracturing".

Ex. 2081, McGowen Dec. at 10

DEVELOPMENT and APPLICATION of "FRAC" TREATMENTS in the PERMIAN BASIN

R. E. HURST
J. M. MOORE
MEMBERS AIME
D. E. RAMSEY
JUNIOR MEMBER AIME

DOWELL INCORPORATED
MIDLAND, TEX.

T. P. 4032

ABSTRACT

The "frac" method of well stimulation has been applied successfully to all producing formations in the Permian Basin area. During the five years since its development, many changes and improvements have been made in treating materials, procedures, and equipment.

A number of fluid carrying agents, having different physical and chemical properties, have been developed to meet various well requirements. The current trend is toward larger gallonage treatments, employing higher injection rates. The use of "down-the-casing" techniques has greatly reduced high surface working pressures, attributable to friction losses resulting from injection through tubing.

Petrographic studies of various Permian Basin formations, coordinated with laboratory and well log data, have been found a valuable guide in planning frac treatments. A knowledge of the extent and orientation of naturally occurring fractures and planes of weakness in the formation, aid in predicting the ultimate drainage pattern resulting from the frac treatment.

INTRODUCTION

The South Permian Basin covers an area in West Texas and New Mexico about one-half the size of the state of Texas. This vast region has been called the "Permian Basin" for so long that the term will be u here. It includes an area south of the Matador A approximately 250 miles wide and 300 miles long. St tural features of importance within the basin are Northwest Shelf, Eastern Platform, Midland Basin, C tral Basin Platform, and Delaware Basin. The princ producing formations include sand, limestone and d mite, with lesser amounts of shale, anhydrite, chert, various silicates.

All of the producing formations in the Permian Basin have responded to some type of frac treatment. Essentially, a frac treatment may be defined as the injection, into a formation, of a fluid carrying agent containing a particulated solid (usually sand), for the purpose of increasing production. The application of this method of well stimulation to many differing Permian Basin reservoirs has necessitated numerous changes and improvements in carrying agents, solids, service equipment, well equipment, and treating techniques.

CARRYING AGENTS

A number of different types of fluid carrying agents have been developed since the introduction of the frac method of well stimulation. These agents have different physical and chemical properties, and in many cases the extent of production increase derived from the frac treatment depends on the choice of fluid carrier. Unfortunately, due to many different systems of nomenclature used in the oil field, these differences are not always recognized by the oil operator. In general, carrying agents may be divided into the following broad classi-

Manuscript received in Petroleum Branch office on Oct. 1, 1954. Paper presented at Petroleum Branch Fall Meeting in San Antonio, Oct. 17-20, 1954.

Discussion of this and all following technical papers is invited. Discussion in writing (3 copies) may be sent to the offices of the Journal of Petroleum Technology. Any discussion offered after Dec. 31, 1955, should be in the form of a new paper.

SPE 405-G

Ex. 2088
IPR2016-01506

It should not be inferred that frac treatments are a cure-all that eventually will replace other methods of well stimulation, such as acidizing. Some formations, especially those in a plugged condition, require an acid treatment preceding the frac treatment. Almost any zone will be benefitted by a spearhead of regular or mud acid. Such a pretreatment results in lowering injection pressures and dissolving materials that may cause restriction to flow.

R.E. Hurst, "Development and Application of 'Frac' Treatments in the Permian Basin," SPE 405 (1954) at 4; Paper 51, POR at 47.

UNITED STATES PATENT OFFICE

2,689,009

ACIDIZING WELLS

Harold W. Brainerd, Jr., Clarence R. Fast, and George C. Howard, Tulsa, Okla., assignors to Stanolind Oil and Gas Company, Tulsa, Okla., a corporation of Delaware

No Drawing. Application April 14, 1951, Serial No. 221,136

20 Claims. (Cl. 166—25)

1

This invention pertains to a well-treating solution and to an improved method of treating wells to increase their productivity.

In the art of completing wells or working over old wells to increase the output, acid is injected into the producing zones to increase the permeability of the formation around the well. Since acid reacts very rapidly with calcareous formations, it appears that the action of the acid is very close to the well. Accordingly, the effect of acidizing a well is generally to increase output, but the increase appears to be much less than would be possible if the acid could be made to react into long channels deep into the formations.

It has been proposed that strong mineral acids which are used to acidize formations penetrated by a well be incorporated as the discontinuous phase in an acid-oil emulsion. By thus shielding the acid, it is prevented from contacting the well tubing and the calcareous formations as the acid is injected into a well. Corrosion of the tubing is avoided, and the reaction of the acid on the formation is retarded. Certain oils are known to emulsify with acids; and, in some cases, the emulsion may be produced by incorporating in the oil or the acid certain emulsifying agents. This proposal has not been used, since, in practice, it has been found that the emulsifying agents proposed are either too stable or too unstable. That is, if the emulsion is too stable, the emulsion may not be easily broken down in the well or in the formation; and, if injected into a formation, as by the application of a high pressure, the emulsion cannot be displaced from the pores of the formation by the relatively small available natural driving force. The formation would thus be plugged if such stable emulsions were forced into the capillaries surrounding a well. If the emulsion is unstable, it is of no value for the intended purpose. In either case, however, the action of the acid is close to the well, and long flow channels into the formation are not produced.

It is an object of this invention to provide an improved well-treating solution. It is another object of this invention to provide a well-treating solution comprising an emulsion of an acid and an oily vehicle which can be injected into a formation at high pressure to fracture the formation and which subsequently can be removed from the formation without plugging the pores thereof. A

2

still further object of this invention is to provide an improved process for increasing the permeability of calcareous formations which produce oil or gas or other valuable fluids.

This invention, in brief, comprises a well-treating solution in which acid is emulsified in an oil dispersion of Batu gum and an improved process in which the viscous emulsion is injected into a formation at a pressure great enough to fracture the formation.

Batu gum is a natural resin related to the Damar natural resins and is a secretion or exudation of the Shorea tree of the East Indies. It is soluble in aryl or coal tar hydrocarbons and in hydrogenated aliphatic petroleum solvents but is generally only very slightly soluble in crude petroleum or refined paraffinic petroleum hydrocarbons. It is, however, compatible with and can be dispersed in paraffinic hydrocarbons, both crude and refined. It is available commercially as bold scraped, unscraped, nubs and chips, and as dust.

The acid phase of the emulsion may be any acid, such as hydrochloric, nitric, or hydrofluoric, which reacts with the formation and produces a water-soluble salt. The most important well acid is hydrochloric acid in the concentration range from about 5 to about 20° Bé. The higher concentrations are preferred in view of the increased reaction rate and the decrease in breakdown time for the emulsion. The vehicle in which the acid of our treating solution is emulsified may consist of non-aqueous liquids, such as liquid petroleum hydrocarbons, e. g., crude oil, kerosene, diesel fuel, or

BAKER HUGHES, A GE COMPANY, LLC AND BAKER HUGHES OILFIELD OPERATIONS LLC
Exhibit 1137
BAKER HUGHES, A GE COMPANY, LLC AND BAKER HUGHES OILFIELD OPERATIONS LLC v. PACKERS PLUS ENERGY SERVICES, INC.
IPR2016-01506

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Ex. 1137, Brainerd at 1; see also Ex. 2087

Patented Sept. 14, 1954 2,689,009

UNITED STATES PATENT OFFICE

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but ... ver ... uni ... har ... Ba ... and ... and ... gro ... sie ... rat ... Ba ... sio ... As ... em ... stit ... 12

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Ex. 1137, Brainerd at 1

Q. How do you know that?

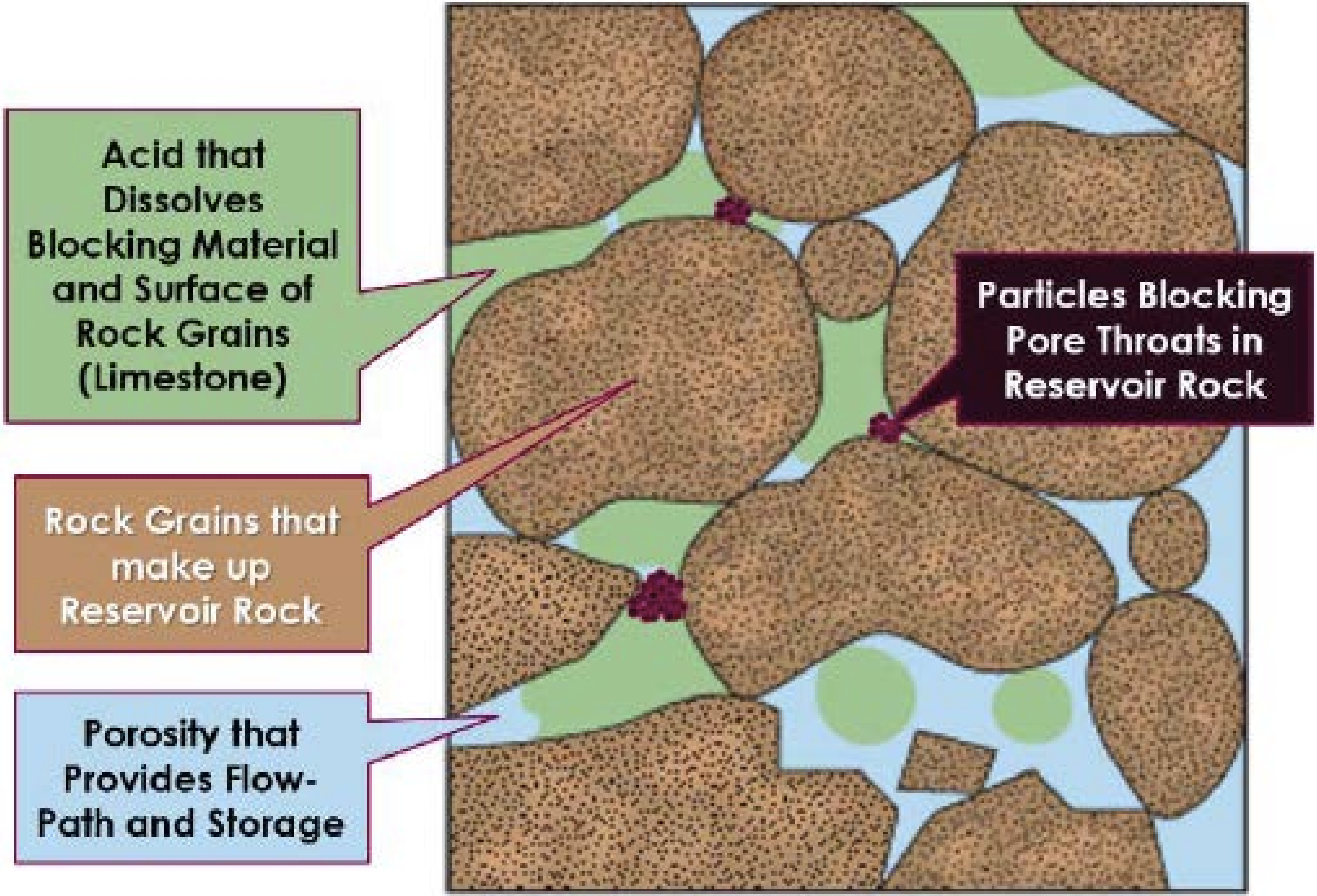
A. Just he says two of the wells were acid stimulated unsuccessfully. He doesn't say whether they were acid fractured or acid -- matrix acidized. They just used acid to stimulate the well. And, of course, immediately after that it says, "Subsequently two transverse fracture treatments were pumped.“ So the author was not hesitant to use the word "fracture."

Ex. 2085, A. Daneshy Depo. at 33:7-34:9

Q. Were the first two Gallup wells fractured then?

A. We don't know. We don't know. Oh. We don't know that they were fractured. We know that they were stimulated.

Ex. 2085, A. Daneshy Depo. at 33:7-34:9


Acid that Dissolves Blocking Material and Surface of Rock Grains (Limestone)
Rock Grains that make up Reservoir Rock
Porosity that Provides Flow-Path and Storage
Particles Blocking Pore Throats in Reservoir Rock

The non-Priority Provisional Application Does Not Limit the Construction of "Solid Body Packer"

- *MPHJ Tech. Investments, LLC v. Ricoh Americas Corp.*, 847 F.3d 1363, 1367 (Fed. Cir. 2017)
- *dunnhumby USA, LLC v. emnos USA Corp.*, No. 13-CV-0399, 2015 WL 1542365, at *11 (N.D. Ill. Apr. 1, 2015)
- *Ring Plus, Inc. v. Cingular Wireless, LLC*, No. CIV.A. 2:06-CV-159DF, 2007 WL 5688765, at *10 (E.D. Tex. July 9, 2007)

Thus, as understood by a person of ordinary skill in the art, the term “solid body packer” would mean “packer including a solid, extrudable packing element.”

Ex. 1005, A. Daneshy Dec. at 40.

60404783.082102

3

In another embodiment, instead of the shearable caps, sliding port sleeves can be used to control fluid passage through ports. In particular, a series of limited entry moveable sliding port sleeves are installed over a plurality of ports in a casing string. A ball or plug is introduced to the string and pumped into the well. The ball engages a shifting sleeve and fluid pressure behind the ball/sleeve will move it down in the well. When the shifting sleeve passes through the limited entry port sleeve, a set of shifting dogs or keys engage in a shoulder or profile on the port sleeve. As they engage, the port sleeve is shifted to the open position not covering the port and the limited entry port is exposed. The shifting dogs to release, as by increasing pressure behind the ball/sleeve and the shifting sleeve moves downward to the next limited entry port sleeve.

The process continues until all sleeves are shifted to the open position. The shifting sleeve will stop when it reaches a shoulder and will stop fluid from entering the toe end of the well. All or most additional fluid will be diverted through the newly exposed ports.

Lateral wellbore isolation system (Figure 5)

A wellbore with lateral or sidetrack – multiple legs can be effectively stimulated with a junction isolation system using packers, such as solid body open hole packers, combined with tubing. A solid body packer is defined as a tool to create a seal between tubing and casing or the borehole wall using a packing element which is mechanically extruded, using either mechanically or hydraulically applied force. A
otherwise. When junctions to
important to provide the ability
a junction isolation system can
are placed in a selected lateral
leg form the remainder of the
packer, but is openable to perm
fluids can be pumped down the
Following the stimulation, the

The solid body packers provid
will load into each other to provide additional pack-off. The tubing string may be connected to a packer in the casing to provide additional stability to the system. Also, an open hole slip system may be required to stabilize the packers during pressure pumping operations.

A system to isolate open hole laterals and junctions for stimulation may be used with any wellbore stimulation arrangement such as for example with a "sprinkler", focused packer and sleeve system, or a multiple stage "sprinkler" system, or any combination thereof. It may also be used during production of the well.

Claims – multi-stage sprinkler system:

1. Wellbore fluids can be distributed to segments of the well bore using "limited entry" by creating a pressure drop through pumping flow restrictions.
2. High pumping rates and pressures may be required to achieve limited entry over a long interval.
3. A series for stages to create a sprinkler effect over smaller intervals may reduce the requirements for high pumping rates.
4. Smaller segments that are treated may allow and increase pumping rate per foot of formation being treated may be more effective in establishing fracturing length of fluid distribution.
5. A higher density of fluid exit points may create more effective stimulation results
6. Ports with internal protective covers can be installed in a tubing string and then into a well.
7. The protected ports can provide pressure holding capability to allow stimulation fluids to be routed to other segments of the well.
8. A movable sleeve can be installed into the tubing string that will remove the protective cap from the ports to effectively open the port.
9. A ball or plug can be pumped into a well that will seat in the movable cutter sleeve.
10. Pressure from moving fluids push the moveable cutter sleeve down the wellbore and effectively remove multiple protective caps to open these ports.
11. The moveable sleeve will seat in a no-go to seal off the lower portion of the well.

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A wellbore with lateral or sidetrack – multiple legs can be effectively stimulated with a junction isolation system using packers, such as solid body open hole packers, combined with tubing. **A solid body packer is defined as a tool to create a seal between tubing and casing or the borehole wall using a packing element which is mechanically extruded, using either mechanically or hydraulically applied force.** A well may be drilled with multiple legs or laterals that may be vertical, horizontal, or shaped

Ex. 1012 at 9

For RE Packers, the packing element is mechanically extruded using either mechanically or hydraulically applied force by the mechanical force applied by the metal components of the tool and/or the borehole wall that contact the element as it swells. Moreover, the fluid that enters the element also applies a mechanical or hydraulic force to the element. These forces cause the element to be mechanically extruded as it swells.

Ex. 2051, McGowen Dec. at 82.

Q. Are Baker Hughes's RE packers, are they hydraulically settable?

A. Well, the reactive packer that I'm familiar with is -- operates through wrapping a particular type of elastomer around the casing and it's adhered to the casing. And the nature of the polymer that the material is constructed of is such that it has an affinity for -- it can either be saltwater or hydrocarbon, liquid hydrocarbon. So it generates hydraulic pressure internally as it pulls fluid into the matrix or porosity of the material, and then that causes it to extrude mechanically against the bore hole wall.

Ex. 1131, McGowen Depo. at 116:9-21

Q. If hydraulically settable in the description that I just gave requires axially compressing the swellable element, is that how it's hydraulicly settable?

A. Well, typically it's constrained on either end such that as the material expands, every action has an opposite and equal reaction. So the elastomer material is actually pushing against that and extruding itself out and contacting the bore hole wall. So it's a different mechanism, but it still requires hydraulic pressures just internal to the material and it's still generating mechanical force, because the hydraulic pressure is a force applied over an area, so pounds per square. . . .

Ex. 1131, McGowen Depo. at 117:1-17

Because the evidence shows that the SignalTight connectors are “the invention disclosed and claimed in the patent,” we presume that any commercial success of these products is due to the patented invention.

PPC Broadband, Inc. v. Corning Optical Commc'ns RF, LLC, 815 F.3d 734, 747 (Fed. Cir. 2016) (quoting J.T. Eaton & Co. v. Atl. Paste & Glue Co., 106 F.3d 1563, 1571 (Fed.Cir.1997).)

This evidence demonstrates that there is a nexus between the claimed technology and the commercial success of FracPoint and StackFRAC. In fact, **this technology is such an integral part of these systems that they simply are the invention disclosed and claimed in the 774 patent.**

Ex. 2051, McGowen Decl. at 47
See also claim charts at 63-93

However, if the marketed product embodies the claimed features, and is coextensive with them, then a nexus is presumed and the burden shifts to the party asserting obviousness to present evidence to rebut the presumed nexus. **The presumed nexus cannot be rebutted with mere argument; evidence must be put forth.**

Brown & Williamson Tobacco Corp. v. Philip Morris Inc., 229 F.3d 1120, 1130 (Fed. Cir. 2000) (internal citations omitted)

Q. Are you familiar with the phrase ‘objective evidence of nonobviousness?’

A. Objective evidence of nonobviousness? Can you explain it to me?

Ex. 2016, A. Daneshy Depo. at 109:20-24

We have held that '[w]hile objective evidence of non-obviousness lacks a nexus if it exclusively relates to a feature that was 'known in the prior art,' the obviousness inquiry centers on whether 'the claimed invention as a whole' would have been obvious.'

Where the allegedly obvious patent claim is a combination of prior art elements, we have explained that **the patent owner can show that it is the claimed combination as a whole that serves as a nexus for the objective evidence**.

WBIP, LLC v. Kohler Co., 829 F.3d 1317, 1331–32 (Fed. Cir. 2016) (internal citations omitted).

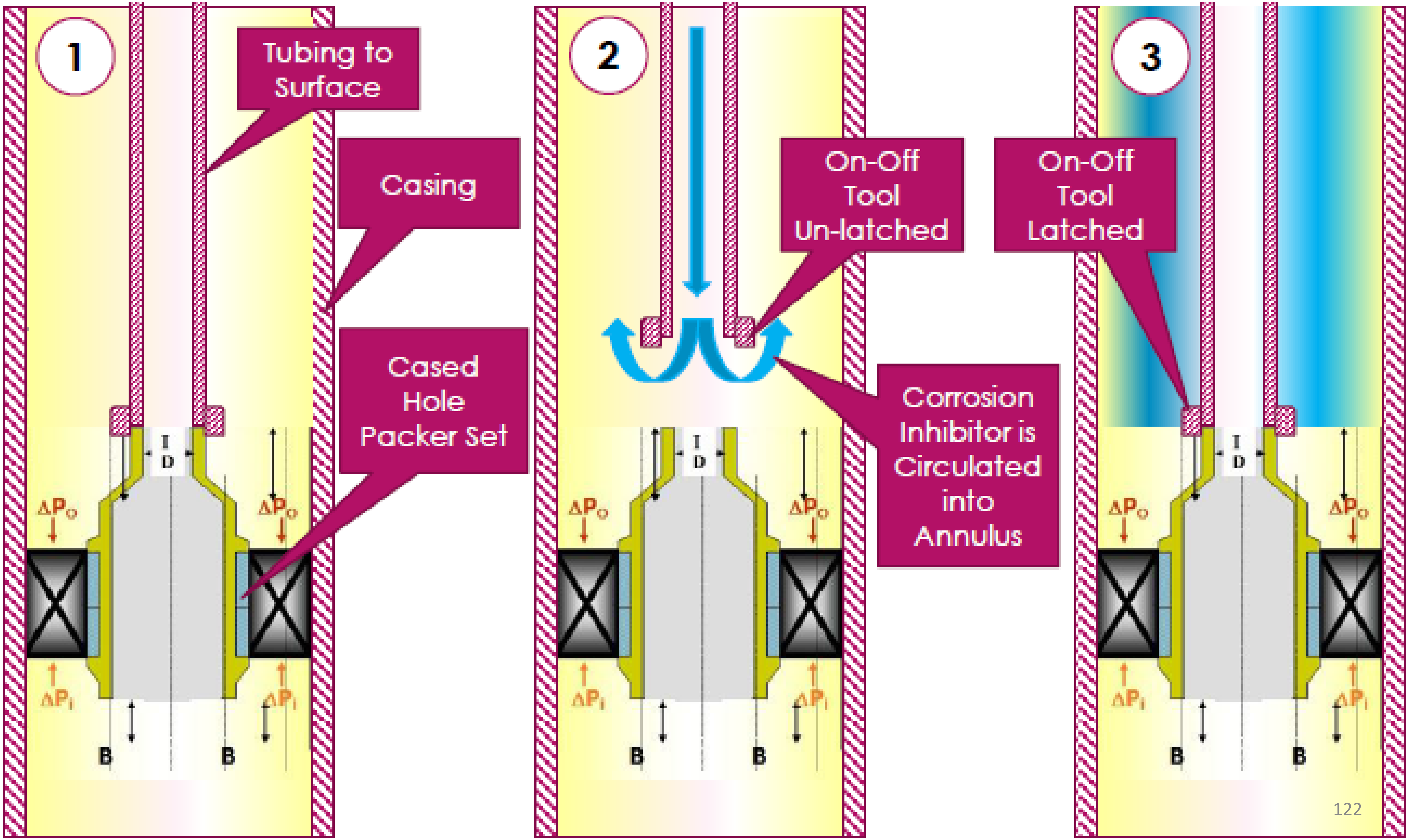
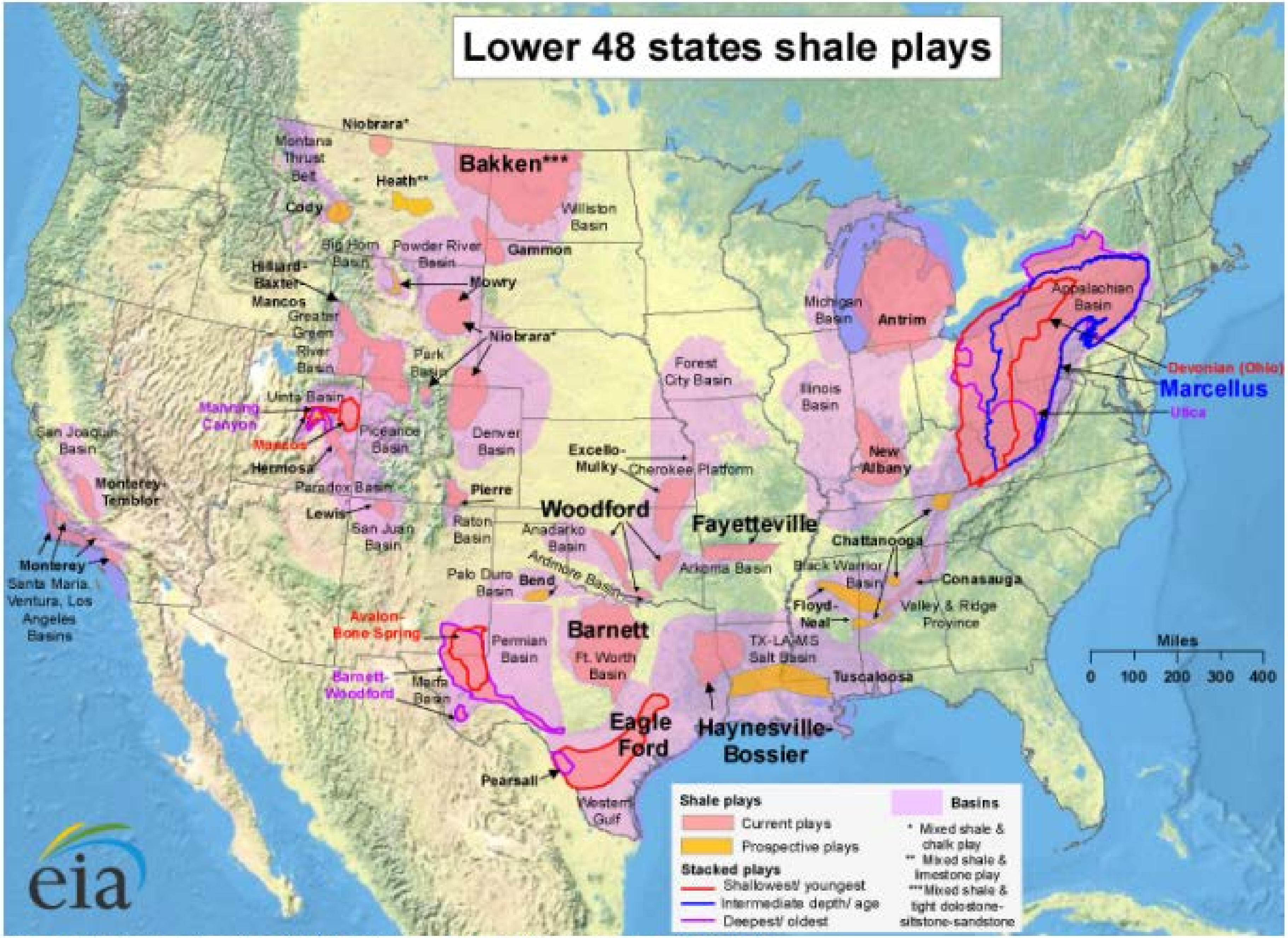

1
Tubing to Surface
Casing
Cased Hole Packer Set
2
On-Off Tool Un-latched
Corrosion Inhibitor is Circulated into Annulus
3
On-Off Tool Latched
ID
ΔPo
ΔPi
B
B

Figure 1. Map of U.S. shale gas and shale oil plays (as of May 9, 2011)



Source U.S. Energy Information Administration based on data from various published studies.
Upeate: May 9, 2011

Dated: October 31, 2017

Respectfully submitted,

Rapid Completions LLC

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CERTIFICATION OF SERVICE

The undersigned hereby certifies that PATENT OWNER'S ORAL HEARING DEMONSTRATIVES were served electronically via e-mail on the following counsel of record for Petitioner:

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