Rapid Completions LLC Response

Weatherford Proceedings

IPR2016-01517 (U.S. Pat. No. 7,134,505)

IPR2016-01514 (U.S. Pat. No. 7,543,634)

IPR2016-01509 (U.S. Pat. No. 7,861,774)

Unless otherwise noted, all citations herein are to the exhibit list for IPR2016-01509 (774 patent). This exhibit list is available in the Patent Owner Response, Paper 32.

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

Q. Well, what I'm asking is this hypothetical person of skill in the art, would they have thought it was obvious prior to 2001 to do open hole multistage fracturing?

A. The -- the obvious part throws me because I don't what you mean by it was obvious. If somebody wished to do multistage fracturing, then -- then they could read Thomson. And Thomson did -- **Thomson did multistage fracturing. So there was literature available to the POSITA to do such a thing, but the motivation by and large was not there.**

Ex. 2101, V. Rao Depo. at 13:11-24.

Q. Prior to November 2001, what was the goal of multistage fracturing in horizontal wells?

A. The same as it would be today, but prior to 2001 there was not much of a call for it and so there was not much work done in that space. In part because the vast majority of the horizontally stimulated wells, horizontal fractured wells, were in the Austin Chalk. . .

Ex. 2044, V. Rao Depo. at 31:14-32:3.

So I'll go back to the Austin Chalk. These are naturally fractured vertical fractures, and some of which were slightly filled with minerals, and the fracturing required to open it up further was not as intensive as -- the pressures required were not as great, so it was not needed.

Ex. 2044, V. Rao Depo. at 32:7-12.

Q. And there's some wells that, prior to 2001, a person skilled in the art would say you know what, plug and perf is a better way to frac this well, as opposed to open hole multistage. You agree with that, right?

A. No.

Q. You would not agree with that?

A. No. See, prior to 2001 there was not much impetus to do any zonal isolation fracturing; because if you look at the history of the – of the years before 2001, for the -- say the decade before 2001, the vast majority of the fracturing was done in Austin Chalk. . .

Ex. 2101, V. Rao Depo. at 11:8-20.

Yost

SPE 19090

Production and Stimulation Analysis of Multiple Hydraulic Fracturing of a 2,000-ft Horizontal Well

by A.B. Yost II, U.S. DOE/METC, and W.K. Overbey Jr., BDM Engineering Services Co.
SPE Members

ABSTRACT

The performance of multiple hydraulic fracturing treatments along a 2000-foot horizontal wellbore was completed in a gas bearing, naturally-fractured shale gas reservoir in Wayne County, West Virginia. Pre-frac flow and pressure data, hydraulic fracturing treatments, and post-stimulation flow and pressure data form the basis from which a comprehensive analysis was performed. Average field production from 72 wells was used as baseline data for the analysis. Such data was used to show the significance of enhanced production from a horizontal well in a field that was partially depleted.

The post-frac stabilized flow rate was 95,000 cubic feet per day (mcf/d) from 2000 feet of horizontal borehole. Under current reservoir pressure conditions, the horizontal well produced at a rate 7 times greater than the field current average of 13 mcfd for stimulated vertical wells. This increase in gas production suggests that horizontal wells, in strategically placed locations within partially depleted fields, could significantly increase reserves.

BACKGROUND

The Federal Government has been investigating the application of high angle and horizontal drilling in tight formations for more than 20 years. The value of high angle drilling and multiple hydraulic fracturing from an inclined or horizontal borehole for maximizing production was recognized in 1969.(1) The first test of the concept was performed by Mobil Oil Corporation in the Austin chalk in which a well inclined to 60° through the pay zone was stimulated three times.(2) The U.S. Bureau of Mines, in cooperation with Columbia Gas and Consolidated Natural Gas, drilled inclined wells in the Devonian shales

References and illustrations at end of paper.

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three times.(2) The U.S. Bureau of Mines, in cooperation with Columbia Gas and Consolidated Natural Gas, drilled inclined wells in the Devonian shales

of West Virginia in 1972(3) and again in 1976.(4) These wells obtained inclinations of 43° and 52° respectively, but production results were mixed and not convincing of the potential for the technique.

Ex. 1002 at 1, Ex. 2081, McGowen Decl. at 15, Paper 32, POR at 45

WEATHERFORD INTERNATIONAL, LLC, et al.

EXHIBIT 1002

WEATHERFORD INTERNATIONAL, LLC, et al.
v.
PACKERS PLUS ENERGY SERVICES, INC.

SPE

Society of Petroleum Engineers

SPE 19090

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by A.B. Yost II, U.S. DOE/METC, and W.K. Overbey Jr., BDM Engineering Services Co.
SPE Members

This paper was prepared for presentation at the SPE Gas Technology Symposium held in Dallas, Texas, June 7–9, 1989.

ABSTRACT

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to induce fractures in the formation as
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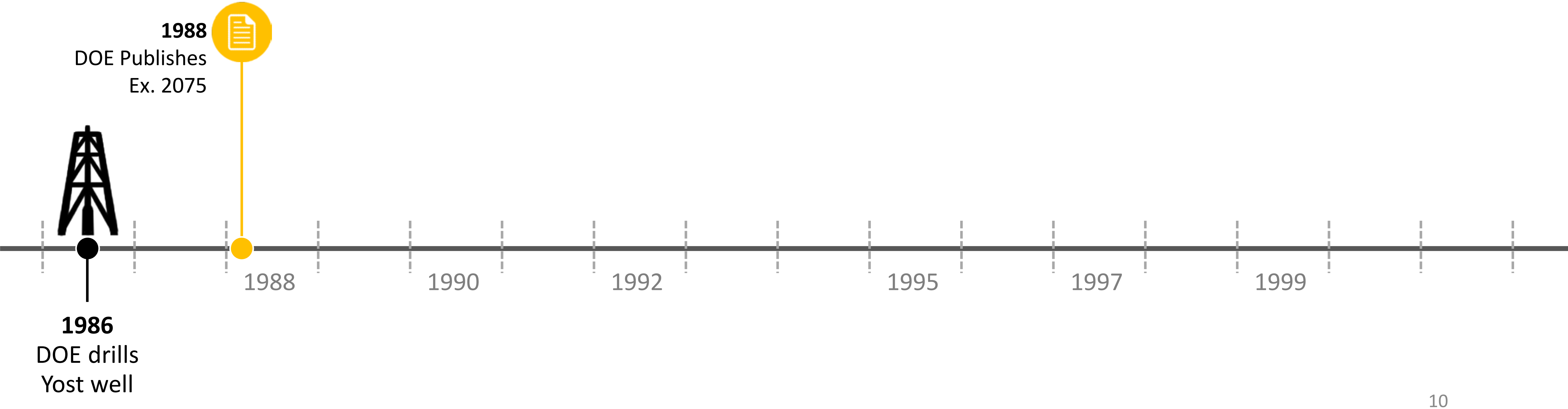
and injection rates.

Well Stimulation Summary

The objective of stimulation research in the horizontal wellbore was to determine the recovery efficiency of the natural fracture system and the effects expected from hydraulically fracturing the well whenever multiple fractures would be induced. To determine the most effective wellbore stimulation under these conditions, it was necessary to use a systematic approach to examine the effects of various combinations of four factors, which were: (1) type of fluid (e.g., gas, liquid, foam); (2) fluid injection rate; (3) volume of fluid injected; and (4) bottomhole treating pressure.

Ex. 1002 at 3, Ex. 2081, McGowen Decl. at 15, Paper 32, POR at 45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SPE
Society of Petroleum Engineers

SPE 17759

Hydraulic Fracturing of a Horizontal Well in a Naturally Fractured Reservoir: Gas Study for Multiple Fracture Design

by A.B. Yost II, U.S. DOE METC; W.K. Overbey Jr., BDM Corp.; D.A. Wilkins, Grace, Shursen, Moore & Assocs.; and C.D. Locke, BDM Corp.

SPE Members

This paper was prepared for presentation at the SPE Gas Technology Symposium, held in Dallas, TX, June 13–15, 1988.

ABSTRACT

Stimulation of a naturally-fractured, low permeability, low-pressure 2000-foot horizontal well in a low permeability reservoir and in-situ stress environment requires careful stimulation fluid design to minimize the capillary retention of treatment fluids. Therefore, a systematic approach to stimulation design using N_2, CO_2, and N_2-foam was used to select one which is most efficient. Stimulation modeling was used to evaluate fracture geometry with particular concern for the minimum pressure rise above parting pressure required for height growth during frac fluid injection. Up to seven zones along the horizontal wellbore are available for stimulation. Each zone was ranked and pre-frac tested to establish pre-frac permeabilities. A N_2 and N_2-foam data frac was performed in one zone to establish leakoff characteristics. Subsequently, N_2, CO_2, and N_2-foam treatments were performed on a 400-foot zone to evaluate the effectiveness of CO_2 versus N_2 frac fluids. Both the data frac and subsequent stimulations were evaluated in the two least productive intervals in order to use the preferred fluids in the best zones in the reservoir. The post-treatment decline curves for N_2 and CO_2 indicate a CO_2-based fluid treatment should be performed in the most productive interval to achieve maximum success. Results of the stimulation conducted are presented along with discussion of improvement ratios and potential utility to other horizontal drilling projects.

BACKGROUND

The stimulation aspects of horizontal drilling represent a technical challenge in tight formations where the horizontal placement of a horizontal wellbore may not always provide adequate economic production. Little or no published literature exists on the mechanics of hydraulic fracturing of horizontal wells. Typically, long horizontal wells are completed with preperforated liners to preserve hole integrity. The disadvantage of this type of completion is the associated risk of pulling the liner at a later stage of production history and re-running and cementing a casing string such that selective placement of fracturing of fluids can be accomplished. An alternative approach is zone isolation accomplished by the installation of external casing packers and port collars as an integral part of a casing string run along the horizontal section. Such a completion arrangement provided stimulation intervals with ready-made perforations injecting fracturing fluids into an open hole fracturing condition behind pipe. This was the method of completion used in this 2000 foot horizontal well to avoid the problems of formation damage associated with cementing and to eliminate the need for tubing-conveyed perforating of numerous treatment intervals.

The U.S. Department of Energy's Morgantown Energy Technology Center has been investigating the merits of drilling high angle wells for more than 20 years. Two high angle wells were completed in the Devonian Shale at 43 and 52° from vertical. Recent emphasis has been on the use of horizontal wellbores to enhance gas recovery efficiency in tight formations.[1] Initial study of horizontal drilling in fractured Devonian Shale in the Appalachian Basin involved selection of a geographic area followed by full-field reservoir simulation and initial well design.[2] Once the site was selected, computer software was used to examine drill string loads, design bottomhole assemblies, track well trajectory, and to provide daily reporting during drilling.[3] Finally, the 2000 foot long horizontal well discussed in this pape was air-drilled to a measured depth of 6020 fee and a true vertical depth of 3403 feet.[4] A vide

References and illustrations at end of paper.

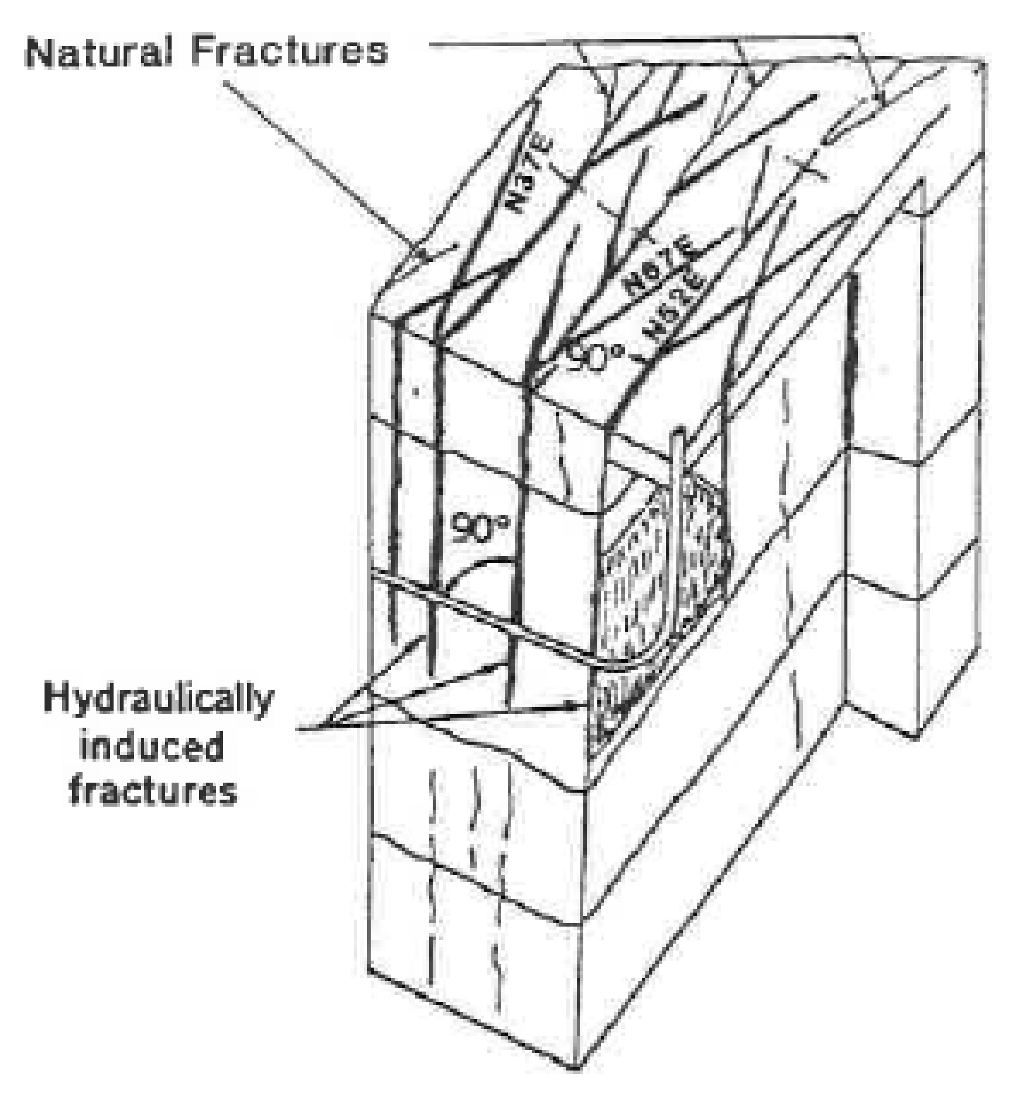

Fig. 2—Elevation view of multiply oriented fractures from horizontal wellbore.

Ex. 2075 at 8, Ex. 2081, McGowen Decl. at 15, Paper 32, POR at 47-48

EXHIBIT 1040
WIT: McGowen
DATE: 7/20/17
A. Blomstrom CRR/CLR/RMR/CSR

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SPE 18249

Inducing Multiple Hydraulic Fractures From a Horizontal Wellbore

by W.K. Overbey Jr., BDM Engineering Services Corp.; A.B. Yost II, U.S. DOE; and
D.A. Wilkins, Grace, Shursen, Moore & Assocs.

SPE Members

This paper was prepared for presentation at the 63rd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Houston, TX, October 2-5, 1988.

II

ABSTRACT

A series of stimulations were designed to open and propagate natural fractures known to exist along a 2000 foot horizontal well in Wayne County, West Virginia. The stimulations were also designed to induce fractures in the formation as well as propagate the natural fractures by manipulating pressure and injection rates. A number of radioactive tracers were used to determine where fractures were opened and propagated at different injection rates. The tracers were found in fractures in zones other than the one pumped into, a fact considered prima facie evidence that natural fractures with two or more orientations had been opened and propagated. Pressure testing and gas sampling of the isolated zones confirm that fracture communication was accomplished along nearly 1000 feet of borehole by stimulation of one 400 foot long section. A technique for inducing multiple hydraulic fractures with multiple orientations was demonstrated.

BACKGROUND

Horizontal wells are drilled to solve production problems or to improve hydrocarbon recovery efficiency from a particular reservoir. It is believed that the original concept of drilling horizontal wells was to contact more formation in a reservoir which was not a particularly outstanding producer, or which had other production problems. One of the earliest known attempts at horizontal drilling in the United States was that done in the Venango sandstone from a shaft drilled near Franklin, Pennsylvania in 1944. The particular problem being addressed was how to produce the heavy crude oil which had lost its solution gas because of the shallow depth of the formation (less than 500 feet) and thus was produced at slow rates.

References and illustrations at end of paper.

Later efforts addressed themselves to tight, low permeability shales and sandstones which were productive only as a funct[...] fractures which are conduits [...] hydrocarbons. The ideal way [...] efficiency is to increase the t[...] fractures which can be connecte[...] for drainage. Thus the concep[...] in a particular direction and [...] angle (40 to 90 degrees) was [...] improving upon the recovery eff[...] wellbore.[1]

A method of improving [...] efficiency of inclined or ho[...] a naturally fractured reservo[...] geometry and flow capacity o[...] as well as create new induced [...] This can best be accomplishe[...] natural fractures which exis[...] by inflating them with a no[...] propping the inflated fractu[...] enhanced flow capacity and [...] fractures by increasing the [...] was the technical approach u[...] recovery from the Devonian sha[...] well. This type of operation can be accomplished quite readily if the right geologic conditions can be found. That condition is generally associated with normal or block faulted areas where multiple fracture directions are generated in association with the faulting. Other conditions where multiple fracture sets are generated are associated with thrust faulted areas. Several geologic settings were selected in Wayne and Lincoln Counties, West Virginia, which were known to have multiple fracture sets as a function of the pre-Cambrian rift-type basement faulting which produced the Rome Trough, and the test well was drilled in one of them[...]

Little published literature exist[...] discusses the relationship of the orient[...] horizontal or inclined wells with respect to [...] trends of faulting and fracturing expecta[...]

The objective of the tests conducted and reported on in this paper is to present evidence supporting our conclusion that two sets of natural fractures were opened and propagated during stimulation operations, and induced fractures along a third direction controlled by the regional stress field. Two systems of fracture diagnostics

Ex. 1040 at 2, Paper 39, Reply at 10

EXHIBIT 1040
WIT: McGowen
DATE: 7/20/17
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SPE 18249

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Later efforts addressed themselves to tight, low permeability shales and sandstones which were productive only as a function of the natural fractures which are conduits for the reservoir hydrocarbons. The ideal way to improve recovery efficiency is to increase the total number of natural fractures which can be connected to a single wellbore for drainage. Thus the concept of drilling a well in a particular direction and attaining an inclined angle (40 to 90 degrees) was a logical means of improving upon the recovery efficiency of a vertical wellbore.[1]

A method of improving the gas recovery efficiency of inclined or horizontal wellbore in a naturally fractured reservoir is to extend the geometry and flow capacity of existing fractures as well as create new induced hydraulic fractures. This can best be accomplished by stimulating the natural fractures which exist in the reservoir by inflating them with a non-damaging fluid and propping the inflated fractures to maintain the enhanced flow capacity and to induce additional fractures by increasing the injection rate. This was the technical approach used to stimulate gas recovery from the Devonian shales in the horizontal well. This type of operation can be accomplished quite readily if the right geologic conditions can be found. That condition is generally associated with normal or block faulted areas where multiple fracture directions are generated in association with the faulting. Other conditions where multiple fracture sets are generated are associated with thrust faulted areas. Several geologic settings were selected in Wayne and Lincoln Counties, West Virginia, which were known to have multiple fracture sets as a function of the pre-Cambrian rift-type basement faulting which pro
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Ex. 1040 at 10, Paper 39, Reply at 10

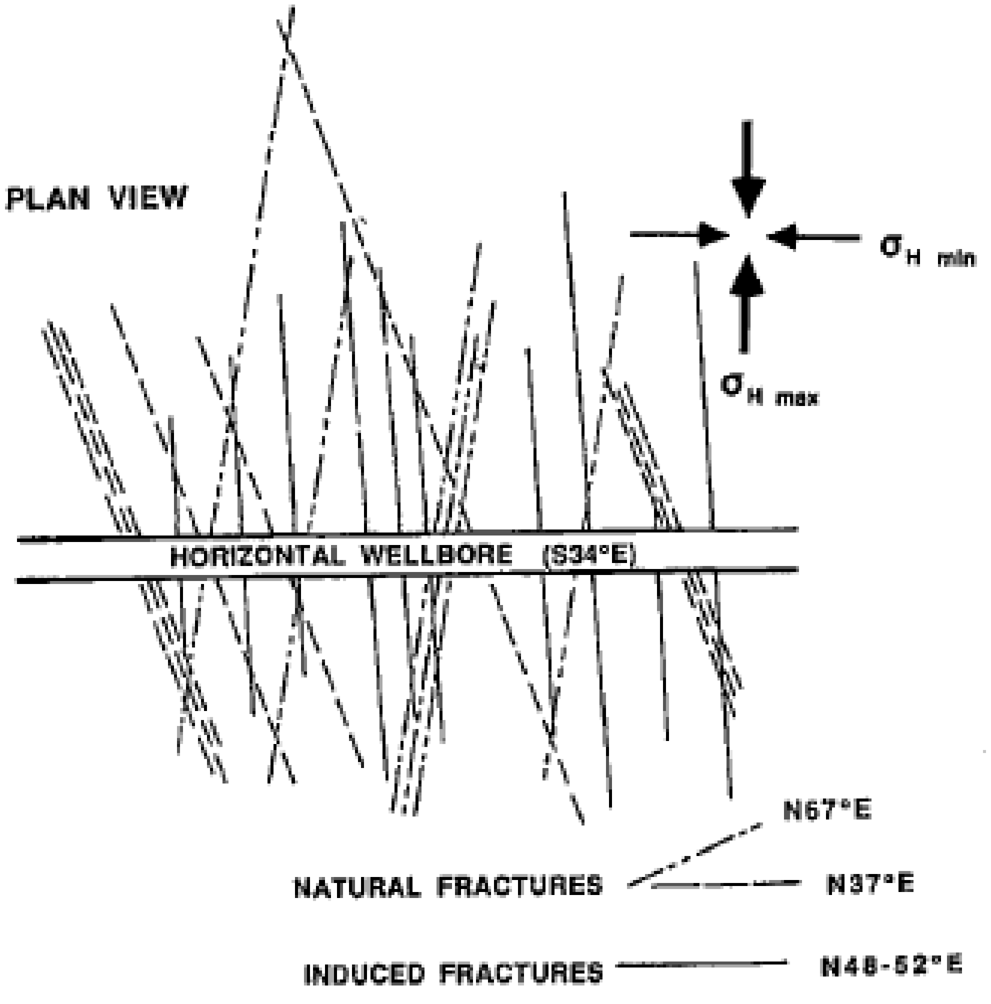

Fig. 6—Diagram illustrating interconnection of small dihedral angle fractures.

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SPE 18255

Insights Into Hydraulic Fracturing of a Horizontal Well in a Naturally Fractured Formation

by A.W. Layne, U.S. DOE, and H.J. Siriwardane, West Virginia U.

SPE Members

II

Horizontal wells are thought to be necessary in formations with low-permeability such as the Devonian shales to increase natural gas recovery and to reduce the risk of drilling a dry hole. In a horizontal well, the bore hole crosses multiple natural fractures in the reservoir. Stimulation data from a 2,000 ft (609.6 m) horizontal well drilled into the Devonian shales in Wayne County, West Virginia, was used in this study. Inflatable packers and casing port collars were used so that individual zones could be tested or stimulated along the wellbore.

This paper focuses on an analysis of hydraulic fracture design and geometry predictions for the above horizontal well. Current hydraulic fracture modeling theories address failure mechanisms and the propagation of a single crack from a vertical wellbore. These theories have been adapted to predict the pressure, flow rate, and induced fracture geometry for each natural fracture intersected by the hydraulic fracturing fluid in the horizontal wellbore. A tubing/annulus flow model was coupled with a hydraulic fracture model that predicts the three-dimensional geometry of multiple natural fractures propagating from a horizontal well. Additionally, a closed-form solution was developed to predict the pressure and flow rate distribution along the lateral extent of the wellbore.

Predicted results were compared with in situ fracture diagnostics from gas (nitrogen and CO_2) and foam stimulation treatments. Radioactive-tracer with spectral-gamma-ray logging confirmed that both fluid pressure and stress perpendicular to the fracture affect the injection flow rate distribution along the wellbore. Both of these factors were used as governing mechanisms for fracture geometry predictions in the simulation model. Predictions based on these models and tracer logs confirm that the single crack theory for fracture propagation is not applicable for stimulations that are initiated along an isolated part of a horizontal borehole.

References and illustrations at end of paper.

BACKGROUND

Recent investigations at the U.S. Department of Energy's Morgantown Energy Technology Center have addressed the potential of horizontal wells to increase the gas recovery from low-permeability formations. A 2000 ft (609.6 m) horizontal well was drilled into the Devonian shale formation in Wayne County, West Virginia, to a measured length of 6,020 ft (1,835 m) and up to a true vertical depth of 3,403 ft (1,037 m).

A schematic of the well configuration is shown in Figure 1. The fracture spacing and locations of casing packers were determined with a downhole video camera and geophysical well logs. Seven zones were isolated along the horizontal section, with external casing packers and port collars as part of the casing string. The port collars and packers were used to isolate stimulation intervals with existing perforations. Fracturing fluids were injected through the port collars into the wellbore tubing and annulus to pressurize the natural fracture system. Stimulations were performed in Zone 1 (see Figure 2) with nitrogen, carbon dioxide, and sand-laden nitrogen foam to determine the most effective fracturing fluid for the shale formation.

INTRODUCTION

The objective of this study on a horizontal wellbore was to determine the recovery effectiveness of the natural fracture system and the impact of stimulating the well by hydraulic fracturing. Five stimulations have been performed. Multiple fractures were propagated simultaneously during these stimulation treatments. The well was drilled in the direction of the minimum principal stress and orthogonal to the major fracture system in the reservoir. *Six natural fracture* orientations were identified with the downhole video camera and geophysical well logs.[1] Figure 2 depicts the natural fracture pattern and orientations in Zone 1. When high-pressure fluid was pumped down the tubing and annulus of the well, numerous natural

Zone 1. When high-pressure fluid was pumped down the tubing and annulus of the well, numerous natural

fractures were enlarged. Actual breakdown of the shale may not have occurred, but fluid leak-off and subsequent expansion of the existing fracture system took place. The objectives of the treatments were (1) to

Ex. 2076 at 1-2, Ex. 2081, McGowen Decl. at 21, Paper 32, POR at 48

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SPE 18255

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Ex. 2076 at 6, Ex. 2081, McGowen Decl. at 21, Paper 32, POR at 48

In a densely fractured reservoir, the creation of significant new crack surface is not apparent because of the multiple low resistance paths available for fluid penetration. It has been observed that the fluids travel along natural fracture orientations and return to the wellbore along intersected natural fractures.

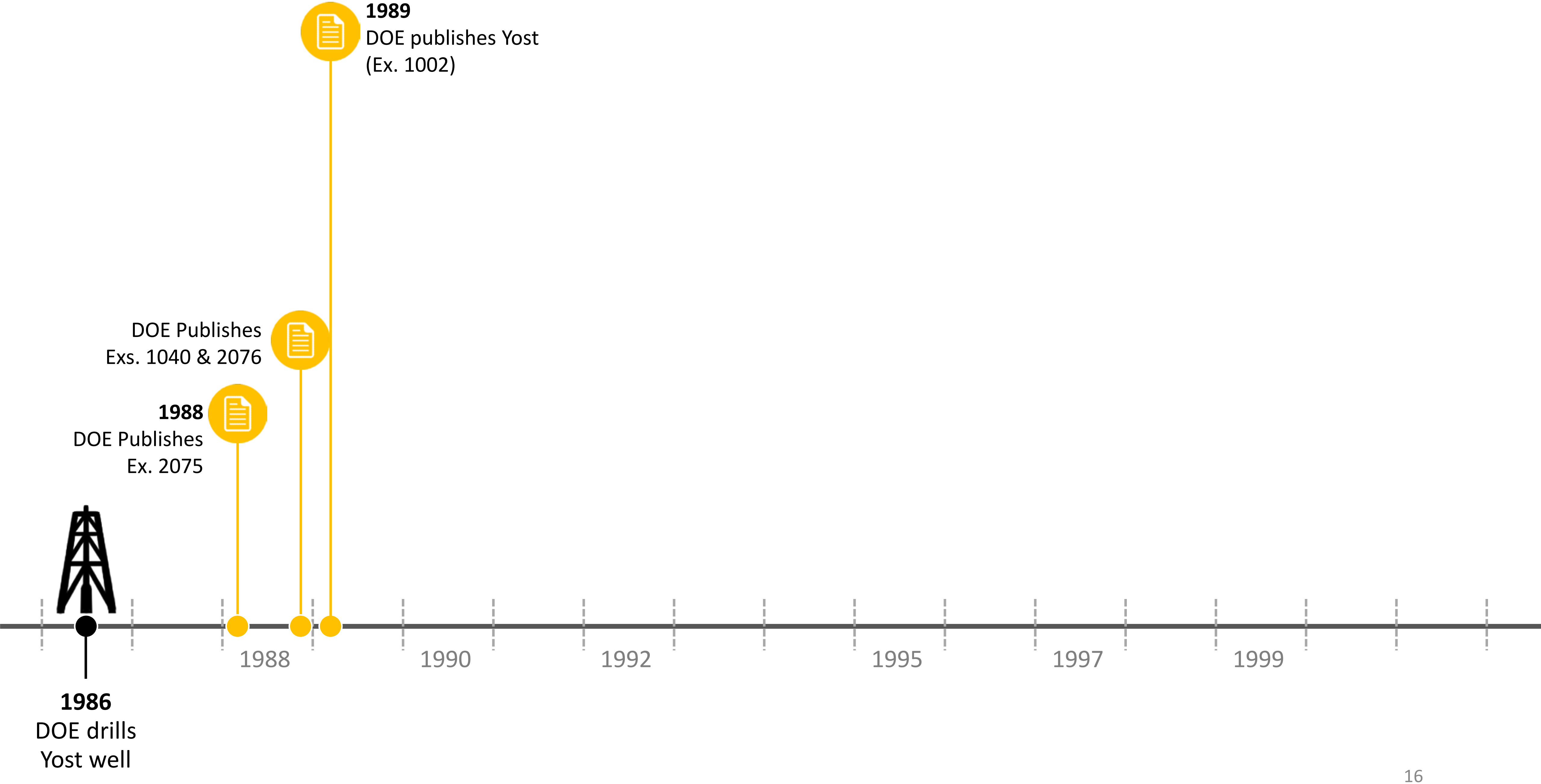
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EXHIBIT 1002

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Production and Stim
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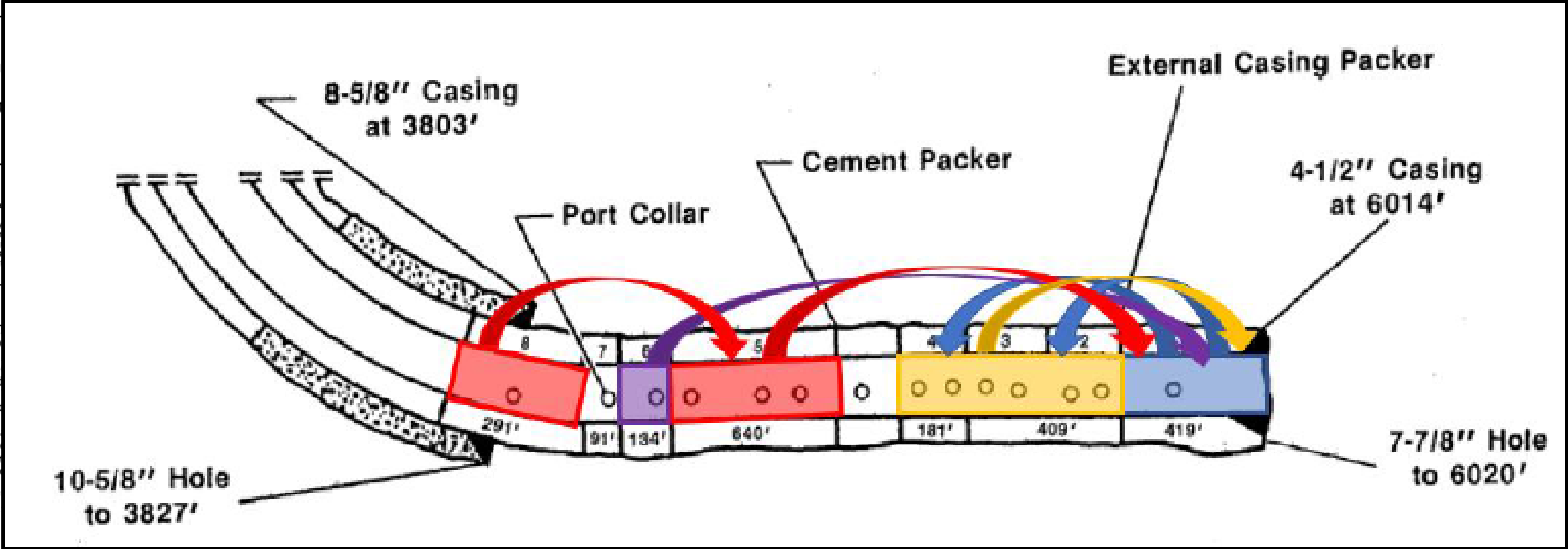

ABSTRACT

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A series of stimulations were designed to open and propagate the many known natural fractures that existed along the 2000 foot length of horizontal wellbore. The stimulations were also designed to induce fractures in the formation as well as propagate natural fractures by manipulating pressure and injection rates.

References and illustrations at end of paper.

Modified Figure from Yost

Ex. 2081, McGowen Decl. at 17, Paper 32, POR at 47

WEATHERFORD INTERNATIONAL, LLC, et al.

EXHIBIT 1002

WEATHERFORD INTERNATIONAL, LLC, e
v.
PACKERS PLUS ENERGY SERVICES, INC

SPE 19090

Production and Stimulation Analysis of Multiple Hydraulic Fracturing of a 2,000-ft Horizontal Well

by A.B. Yost II, U.S. DOE/METC, and W.K. Overbey Jr., BDM Engineering Servic
SPE Members

This paper was prepared for presentation at the SPE Gas Technology Symposium held in Dallas, Texas, June 7-9, 198

ABSTRACT

The performance of multiple hydraulic fracturing treatments along a 2000-foot horizontal wellbore was completed in a gas bearing, naturally-fractured shale gas reservoir in Wayne County, West Virginia. Pre-frac flow and pressure data, hydraulic fracturing treatments, and post-stimulation flow and pressure data form the basis from which a comprehensive analysis was performed. Average field production from 72 wells was used as baseline data for the analysis. Such data was used to show the significance of enhanced production from a horizontal well in a field that was partially depleted.

The post-frac stabilized flow rate was 95,000 cubic feet per day (mcf/d) from 2000 feet of horizontal borehole. Under current reservoir pressure conditions, the horizontal well produced at a rate 7 times greater than the field current average of 13 mcfd for stimulated vertical wells. This increase in gas production suggests that horizontal wells, in strategically placed locations within partially depleted fields, could significantly increase reserves.

BACKGROUND

The Federal Government has been investigating the application of high angle and horizontal drilling in tight formations for more than 20 years. The value of high angle drilling and multiple hydraulic fracturing from an inclined or horizontal borehole for maximizing production was recognized in 1969.(1) The first test of the concept was performed by Mobil Oil Corporation in the Austin chalk in which a well inclined to 60° through the pay zone was stimulated three times.(2) The U.S. Bureau of Mines, in cooperation with Columbia Gas and Consolidated Natural Gas, drilled inclined wells in the Devonian shales

of West Virginia
These wells obta
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References and illustrations at end of paper.

Table 2
Comparison of Pre- and Post-Frac Testing Results

Frac Number	Zone(s)	Pre-Frac Pressure (24 hr) Build-Up (psia)	Pre-Frac Permeability K (md)	Post-Frac Reservoir Pressure (psia)	Post-Frac Permeability K (md)	Post-Frac Skin Value	Pre-Frac Flow Rate (mcfpd)	Post-Frac Flow Rate (mdfpd)
0	All	119*	0.082***	NA	0.20***	-----	34.0	155.0
1	6	74	0.0792	NA	0.1835	-----	2.2	009.0
2 (N_2)	1	54	0.0306	NA	0.0477	-----	2.2	011.0
3 (CO_2)	1	54	0.0306	182	0.0480	-----	2.2	055.0
4 (N_2 Foam)	1	54	0.0306	184	0.0900	-3.212	2.2	034.0
5	2-3	75	0.084**	182	0.1505	-4.220	21.1	062.0
	4	68						
6	5	73	0.071**	178	0.3270	-0.881	9.6	050.0
	8	83						

* Data from 28-day build-up (169 psia bottomhole pressure recorded; 192 psia projected as absolute reservoir pressure)
** Weighted average of individual tests
*** Horner plot calculation

Ex. 1002 at 7, Ex. 2081, McGowen Decl. at 15-16, Paper 32, POR at 45, 59

DOE/MC/25115--3115

DE92 012458

Drilling, Completion, Stimulation, and Testing of Hardy HW#1 Well, Putnam County, West Virginia

Final Report

William K. Overbey, Jr.
Richard S. Carden
C. David Locke
S. Phillip Salamy

The BDM/RET#1 well was an experimental well and more zones were isolated for completion than would normally be done in a well completed for purely commercial purposes. One of the purposes for the

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U.S. Depa
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
BDM Engineering Services Company
7915 Jones Branch Drive
McLean, Virginia 22102

March 1992

Ex. 1036 at 46,
Paper 47
Surreply at 4

DOE/MC/25115--3115

DE92 012458

Drilling, Completion, Stimulation, and Testing of Hardy HW#1 Well, Putnam County, West Virginia

Final Report

William K. Overbey, Jr.
Richard S. Carden

explanation. To initiate a fracture in shale in a horizontal wellbore in a plane other than one containing the wellbore itself, there must be pre-existing natural fractures. Otherwise, the shale is so uniformly impermeable that it would be impossible for fluids to break out of the wellbore without first initiating a longitudinal fracture along the wellbore. The same problem exists with a uniformly permeable formation

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By
BDM Engineering Services Company
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McLean, Virginia 22102

March 1992

Ex. 1036 at 65,
Paper 47
Surreply at 5

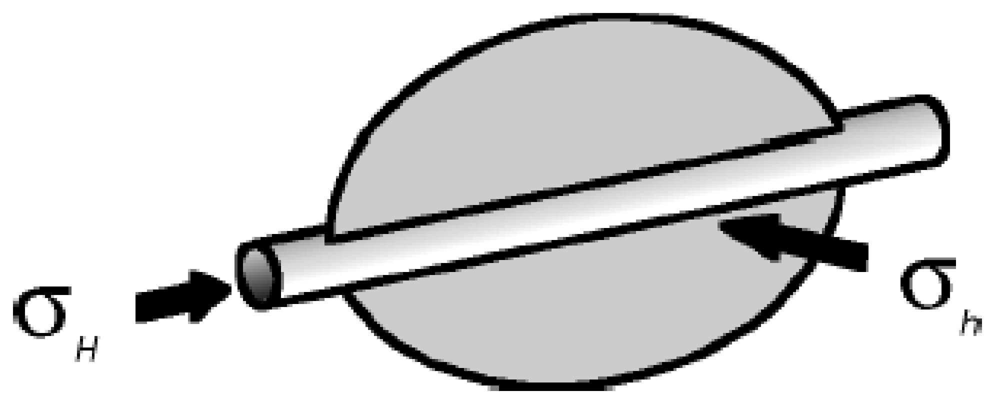


FIGURE 1: Longitudinal fracture configuration.

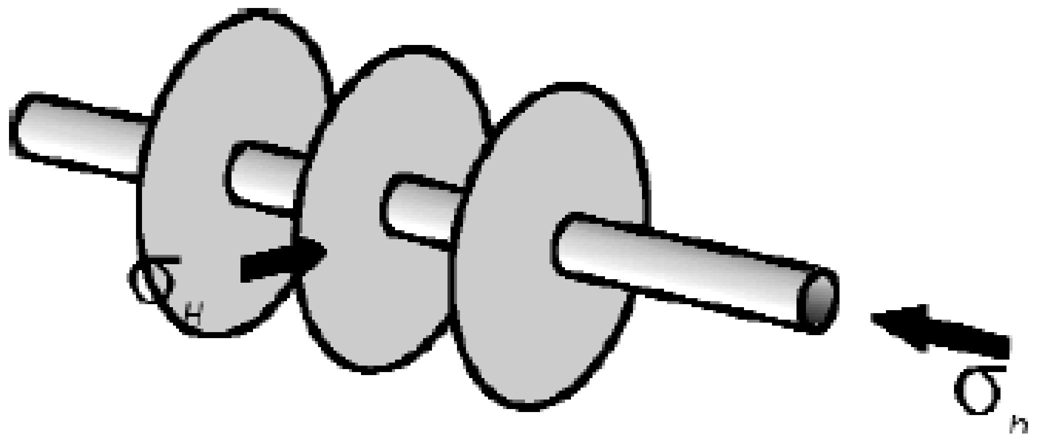
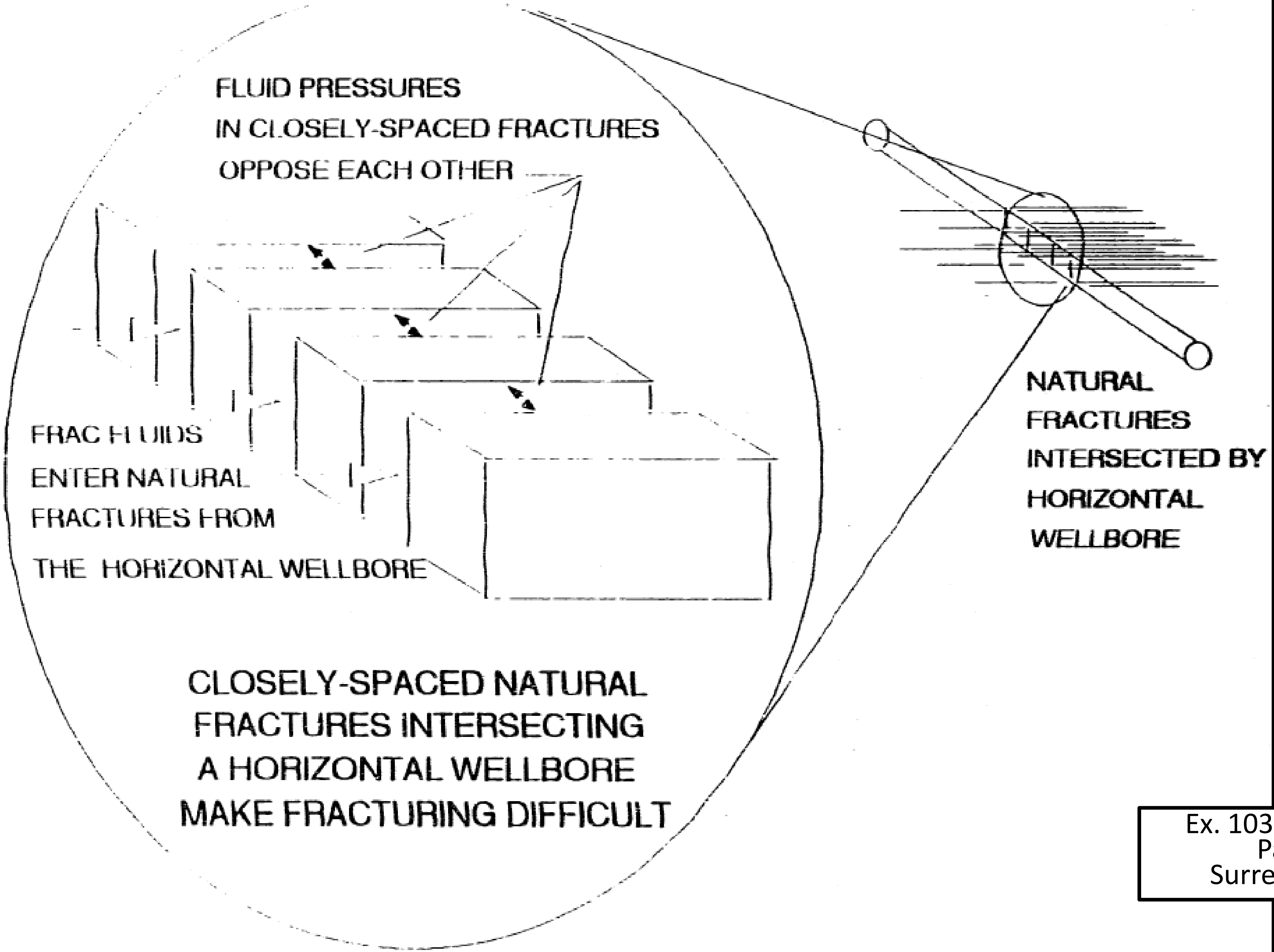


FIGURE 2: Transverse fracture configuration.



Ex. 1036 at 67,
Paper 47
Surreply at 5

DOE/MC/25115--3115

DE92 012458

Drilling, Completion, Stimulation, and Testing of Hardy HW#1 Well, Putnam County, West Virginia

Final Report

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C. David Locke

After the extreme difficulty encountered in fracing Zone 2, plans for the stimulation of Zones 3 and 4 were modified. A shrinking budget necessitated reducing the cost of the remaining stimulation work.

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Morgantown Energy Technology Center
P.O. Box 880

Zone 3-4 was perforated with 42 holes between measured depths of 4207 and 4476 feet. Ten of the holes were in Zone 3 between 4430 and

March 1992

Weatherford International
Ex
Weatherford International LLC et al. v. Packers Plus Energy Ser
IPR20
Page 1 of 231

Ex. 1036 at 66,
Paper 47
Surreply at 5

DOE/MC/25115--3115

DE92 012458

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Work Performed Under Contract No.: DE-AC21-89MC25115

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

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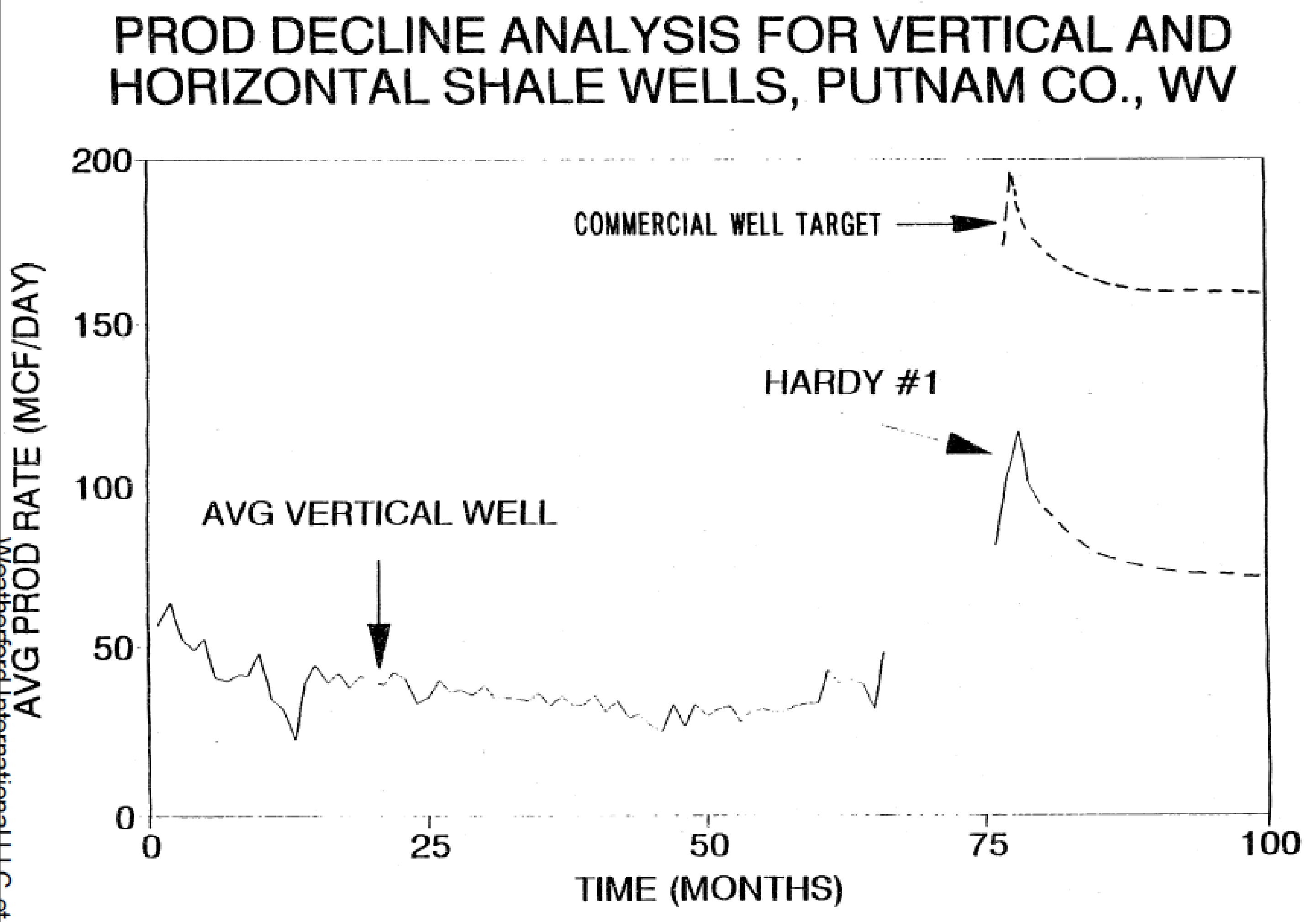
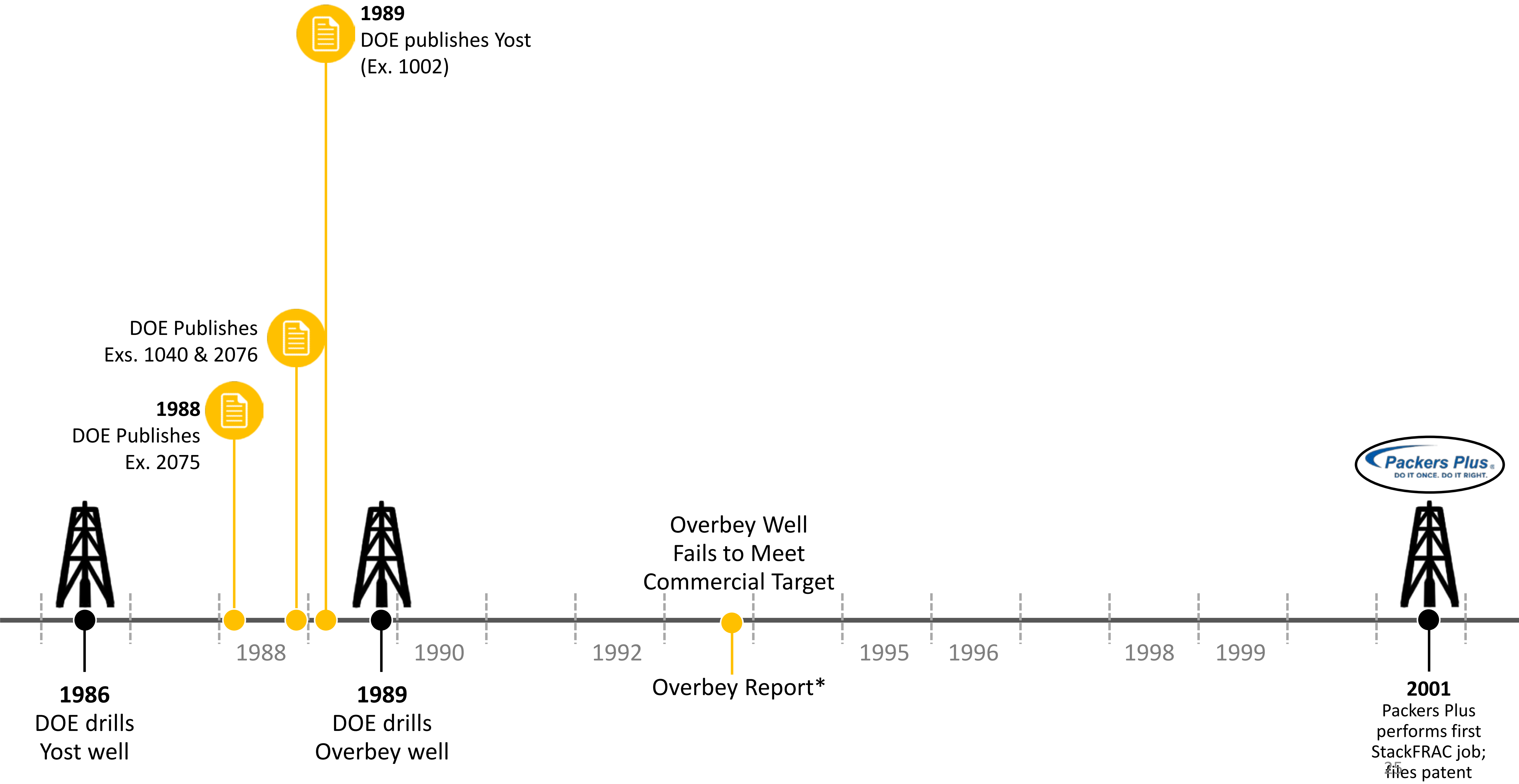


Figure 13.3

Ex. 1036 at 104,
Paper 47
Surreply at 4


1989
DOE publishes Yost
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DOE Publishes
Exs. 1040 & 2076
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Packers Plus
DO IT ONCE. DO IT RIGHT.
Overbey Well
Fails to Meet
Commercial Target
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SPE

Society of Petroleum Engineers

SPE 21264

Air Drilling and Multiple Hydraulic Fracturing of a 72° Slant Well in Devonian Shale

A.B. Yost II,* U.S. DOE; R. Carden, GSM & Assocs.; J.G. Muncey and W.E. Stover, Prime Energy; and R.J. Scheper, Gas Research Inst.
SPE Member

ABSTRACT

This paper discusses site selection, air directional drilling, stimulations, and economic evaluation for a 72° slant well drilled in the Devonian shale, Roane County, West Virginia. The well was drilled to evaluate the concept of using directional drilling and multiple hydraulic fracturing to improve the gas production from a 450-foot naturally fractured Devonian shale section. The well trajectory remained in target for more than 1,500 feet at a preferred azimuthal direction perpendicular to the regional fracture trend and also the known production fairway.

The well was conventionally drilled to the kickoff point of 2,150 feet. Afterwards, positive displacement downhole motors were used to build hole angle up to a 72° hole angle at the top of the target zone. Once the target zone was reached at 67°, conventional rotary assemblies were used to rotate the well across a 1,500-foot target section in which inclination varied from 67° to 72° of hole angle. After reaching total depth of 4,833 feet, the well was logged using wireline and drill pipe conveyed methods. Then 5 1/2-inch casing was run and cemented with 60 rigid centralizers to improve zonal isolation.

Four stimulations were designed and completed. All stimulations will be discussed in the paper. Economic analysis was conducted to show expected improvements from the application of this technology to fractured Devonian shale. Post-stimulation well testing has been identif
zone to show initial results.

References and illustrations at end of paper.

INTRODUCTION

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Energy Technology Center has
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tight gas formations like Dev
tight sands, and coalbeds whe
damaging drilling fluids like air will be used to allow for maximum production from an undamaged formation.

The U.S. Department of Energy developed a cost-sharing contract with Sterling Drilling and Production Company (SD&P) to drill, log, test, and stimulate a high-angle directional well in Roane County, West Virginia. In addition, SD&P developed an R&D agreement with the Gas Research Institute to conduct supporting research in well siting, well logging, testing, and stimulation. SD&P had Columbia Gas and Pennzoil Company as working interest partners in this slant well project.

SITE SELECTION

In order to effectively test this adva
gas recovery concept, shown in Figure

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Ex. 2077 at 1, Ex. 2081, McGowen Decl. at 18-19, Paper 32, POR at 49-50

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This paper was prepared for presentation at the SPE Eastern Regional Meeting held in Columbus, Ohio, October 31–November 2, 1990.

ABSTRACT

This paper discusses site selection, air directional drilling, stimulations, and economic evaluation for a 72° slant well drilled in the Devonian shale, Roane County, West Virginia. The well was drilled to evaluate the concept of using directional drilling and multiple hydraulic fracturing to improve the gas production from a 450-foot naturally fractured Devonian shale section. The well trajectory remained in target for more than 1,500 feet at a preferred azimuthal direction perpendicular to the regional fracture trend and also the known production fairway.

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Ex. 2077 at 1, Ex. 2081, McGowen Decl. at 18-19, Paper 32, POR at 49-50

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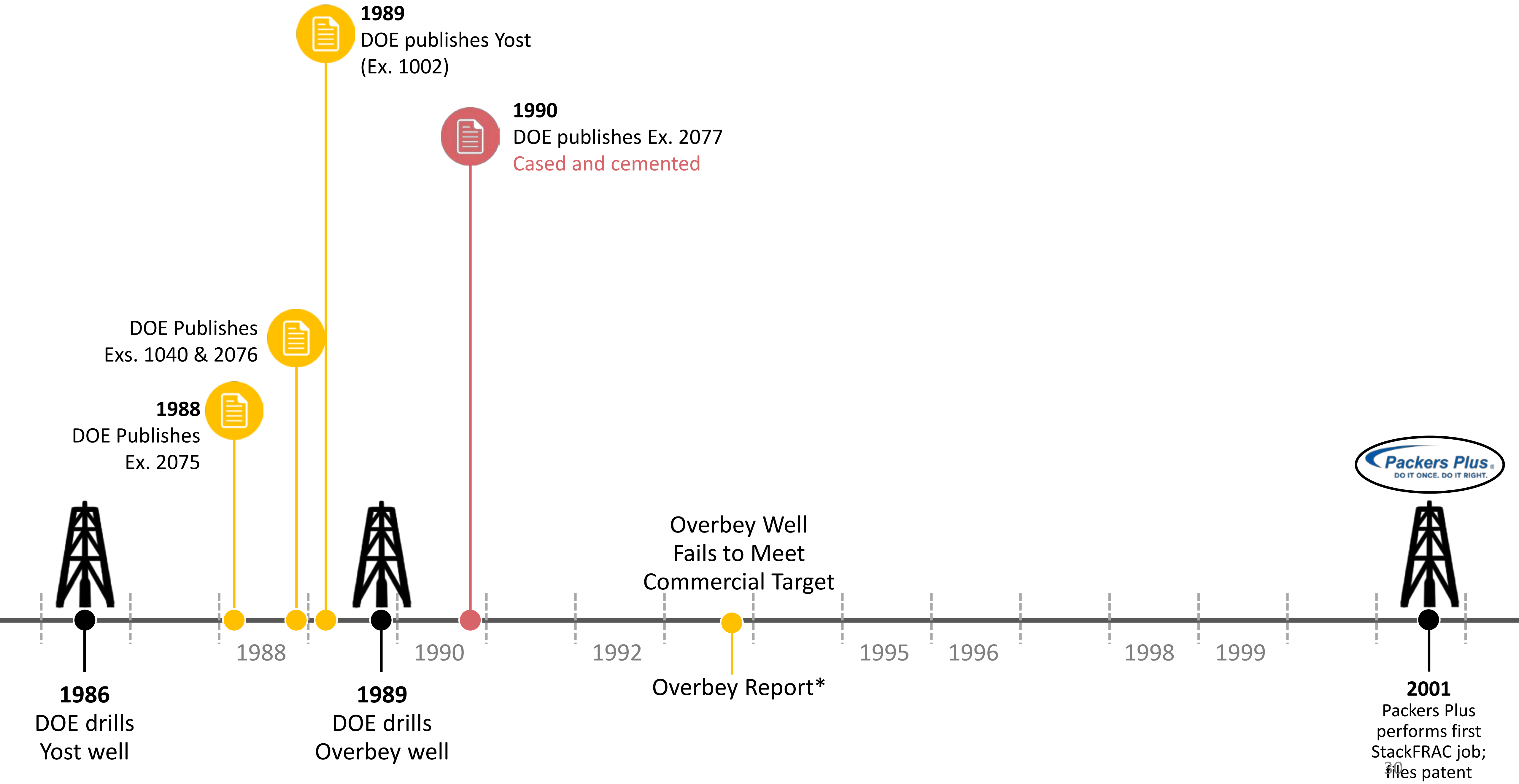
SITE SELECTION

In order to effectively test this adva gas recovery concept, shown in Figure

Ex. 2077
IPR2016-01509

Slant well drilling can improve production three-fold, but the cost of the technology must be reduced to offer economic advantage.

Ex. 2077 at 6, Ex. 2081, McGowen Decl. at 18-19, Paper 32, POR at 49-50


1989
DOE publishes Yost
(Ex. 1002)
1990
DOE publishes Ex. 2077
Cased and cemented
DOE Publishes
Exs. 1040 & 2076
1988
DOE Publishes
Ex. 2075
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Overbey Well
Fails to Meet
Commercial Target
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DOE drills
Overbey well
2001
Packers Plus
performs first
StackFRAC job;
files patent

Society of Petroleum

SPE 37354

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

William F. Murray Jr., SPE, Belden & Blake Corporation, Leo A. Schrider, SPE, Belden & Blake Corporatio
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 approxima
MCF of natural gas and 7,000 barrels of oil in
year of production. Unlike similar wells drilled
the oil production is about twice that expected v
production is less than half of the neighbo
Based on the production performance to date
displayed a much shallower gas decline rate th
well in the area, the CW #14 is currently estim
an ultimate recovery in the range of 330 to 4
which is approximately 1.6 to 2.0 times its ve
wells.

While we are encouraged with the 1.6 to
in estimated ultimate recovery, horizontal drill
appear to be a viable economic alternative
development in this area without further impr
reserve potential along with significant cost red
this time, drilling this type well may be limite
applications for secondary or enhanced oil
perhaps for natural gas storage. The CW #1
drilling project, however, successfully demonstr
extremely hard and abrasive Clinton Sa
horizontally drilled and stimulated which we
major technical accomplishment for drilling a
type in the Appalachian Basin.

Introduction

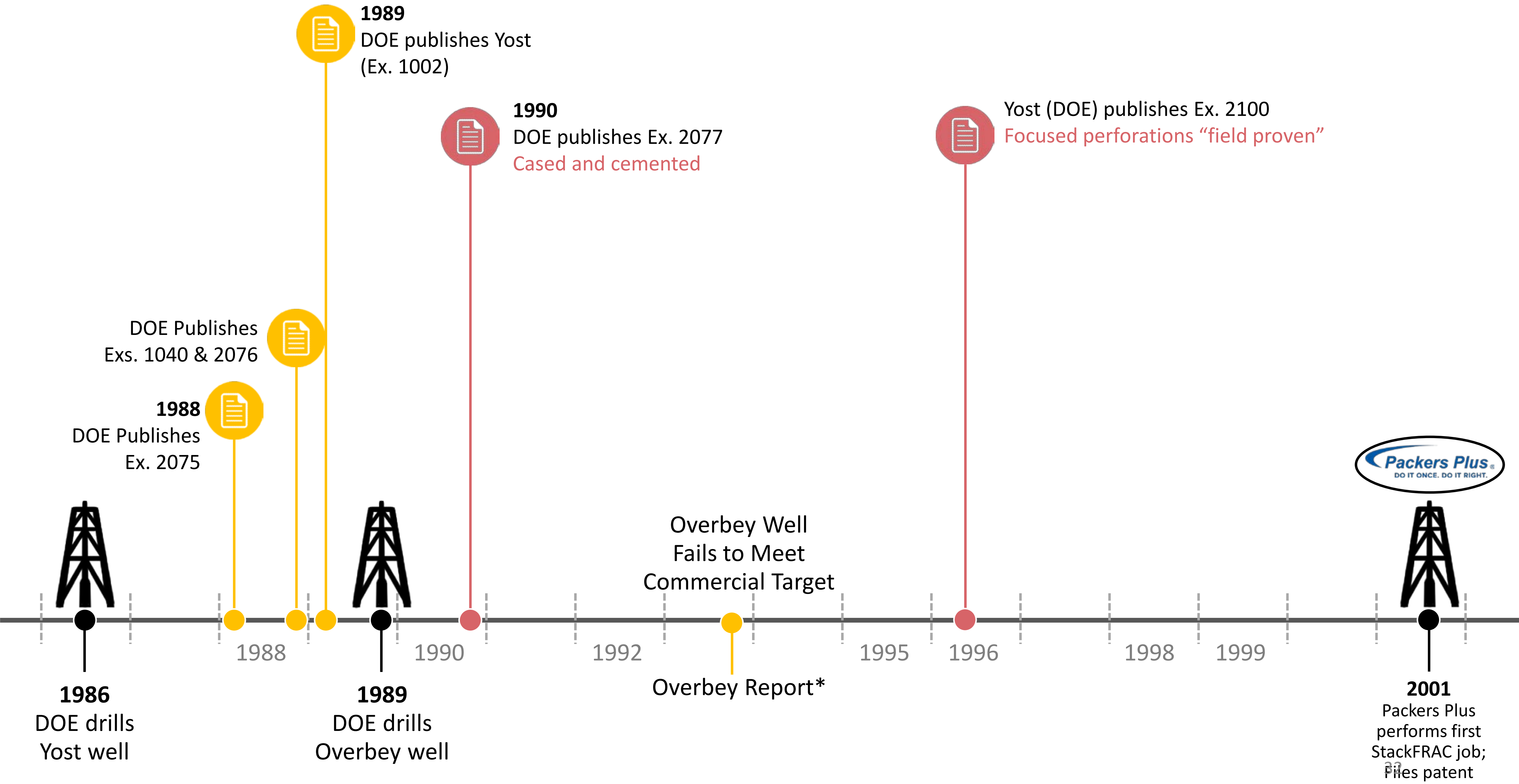
The Clinton Sand is a low permeable gas
Northeastern Ohio with initial well production
the 75 to 150 MCF per day and 5 to 10 barre
day. Ultimate production from a vertical
Clinton formation in Smith Township, Mahoni
projected to be about 205 million cubic

Ex. 2100
IPR2016-01509

Stimulation Rationale. Many options were considered on what could be the best way to properly complete and stimulate a horizontal well in the Clinton Sandstone. Virtually, all

After reviewing many case histories and drawing from Belden & Blake's experience from the offset high angle well (CW #7), 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. Another factor

Ex. 2077 at 1, Ex. 2081, McGowen Decl. at 24, Paper 32, POR at 49-50


1989
DOE publishes Yost
(Ex. 1002)
1990
DOE publishes Ex. 2077
Cased and cemented
Yost (DOE) publishes Ex. 2100
Focused perforations “field proven”
DOE Publishes
Exs. 1040 & 2076
1988
DOE Publishes
Ex. 2075
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DO IT ONCE. DO IT RIGHT.
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StackFRAC job;
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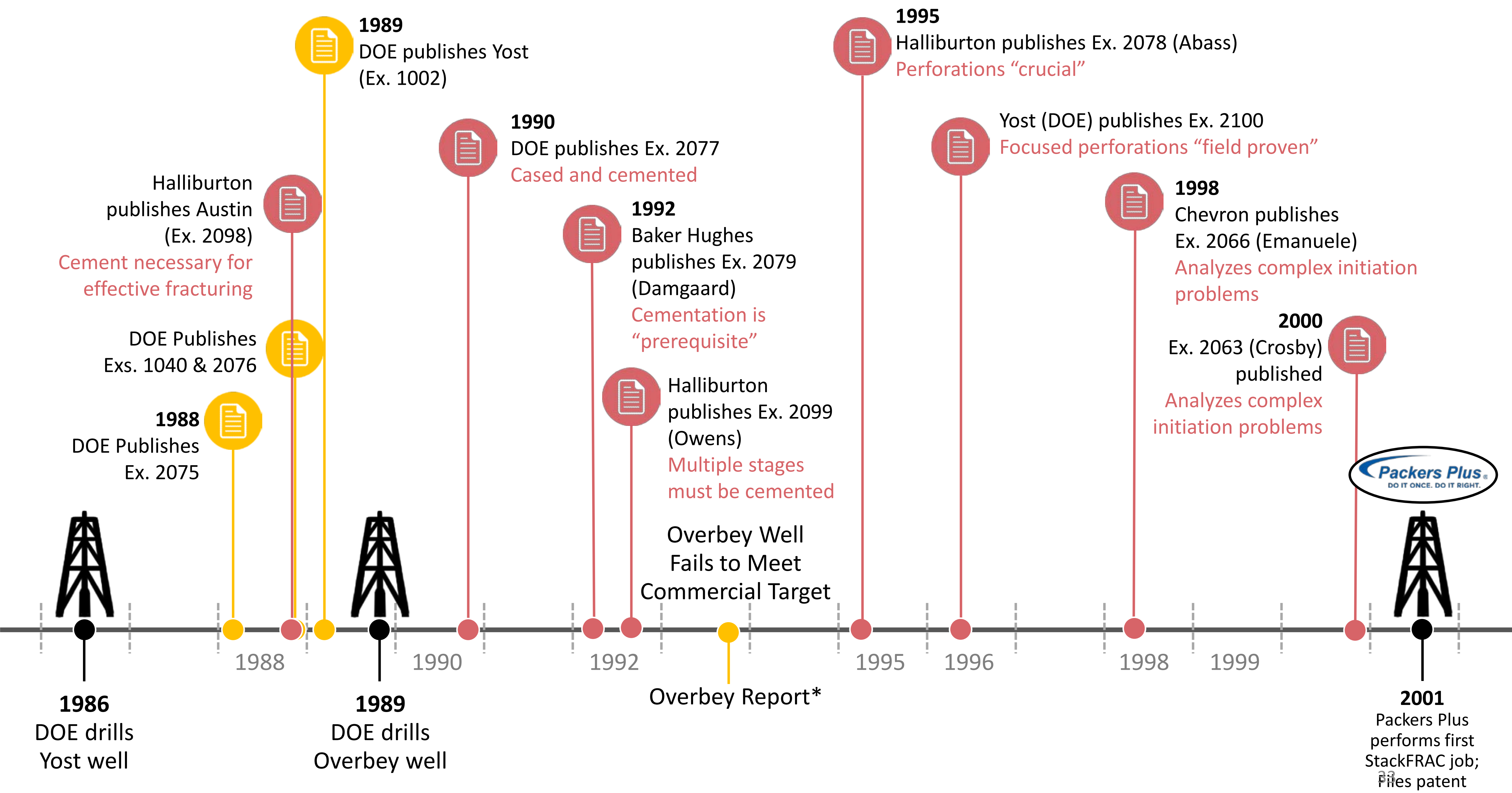
1989
DOE publishes Yost
(Ex. 1002)
1995
Halliburton publishes Ex. 2078 (Abass)
Perforations “crucial”
1990
DOE publishes Ex. 2077
Cased and cemented
Yost (DOE) publishes Ex. 2100
Focused perforations “field proven”
Halliburton
publishes Austin
(Ex. 2098)
Cement necessary for
effective fracturing
1992
Baker Hughes
publishes Ex. 2079
(Damgaard)
Cementation is
“prerequisite”
1998
Chevron publishes
Ex. 2066 (Emanuele)
Analyzes complex initiation
problems
DOE Publishes
Exs. 1040 & 2076
2000
Ex. 2063 (Crosby)
published
Analyzes complex
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1988
DOE Publishes
Ex. 2075
Halliburton
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(Owens)
Multiple stages
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Overbey Report*
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Yost well
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DOE drills
Overbey well
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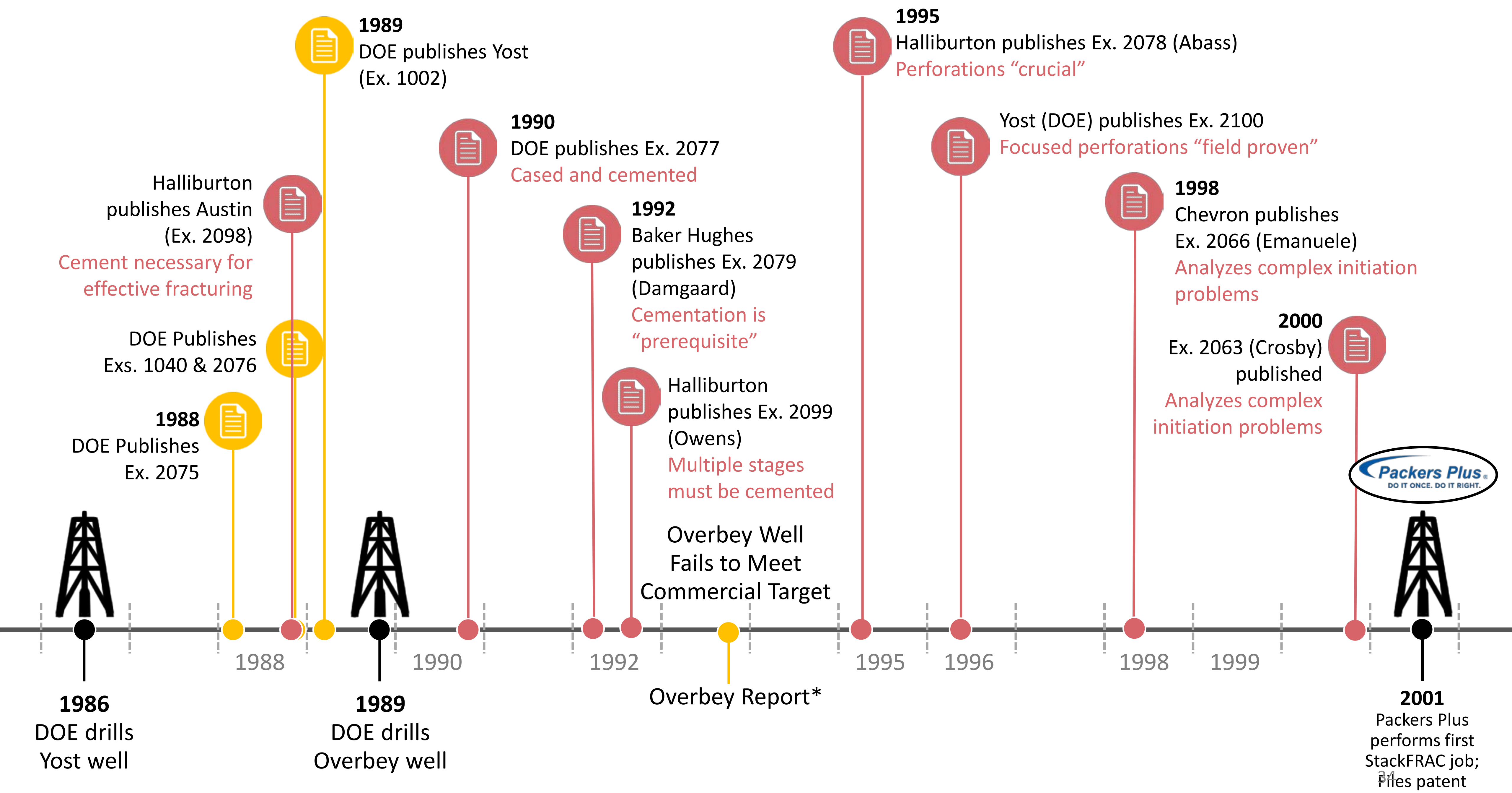
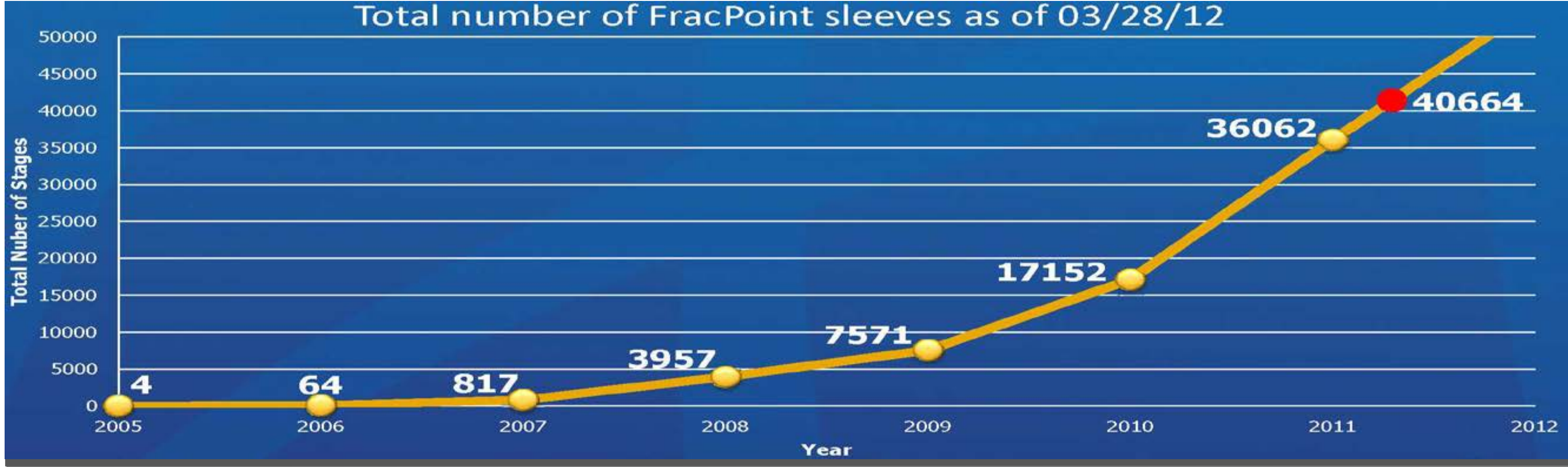
StackFRAC job;
Files patent


1989
DOE publishes Yost
(Ex. 1002)
1990
DOE publishes Ex. 2077
Cased and cemented
Halliburton
publishes Austin
(Ex. 2098)
Cement necessary for
effective fracturing
DOE Publishes
Exs. 1040 & 2076
1988
DOE Publishes
Ex. 2075
1992
Baker Hughes
publishes Ex. 2079
(Damgaard)
Cementation is
"prerequisite"
Halliburton
publishes Ex. 2099
(Owens)
Multiple stages
must be cemented
Overbey Well
Fails to Meet
Commercial Target
1995
Halliburton publishes Ex. 2078 (Abass)
Perforations "crucial"
Yost (DOE) publishes Ex. 2100
Focused perforations "field proven"
1998
Chevron publishes
Ex. 2066 (Emanuele)
Analyzes complex initiation
problems
2000
Ex. 2063 (Crosby)
published
Analyzes complex
initiation problems
1988
1990
1992
1995
1996
1998
1999
1986
DOE drills
Yost well
1989
DOE drills
Overbey well
Overbey Report*
2001
Packers Plus
performs first
StackFRAC job;
Files patent



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

2012
Packers Plus receives Sproule Engineering Award

2003 2005 2006 2007 2009 2010 2012

[O]bviousness generally requires that a skilled artisan have reasonably expected success

Institut Pasteur & Universite Pierre Et Marie Curie v. Focarino, 738 F.3d 1337, 1346 (Fed. Cir. 2013)

Thomson

Q. Does claim 1 of the '774 patent require pumping fracturing fluid into an open hole annular segment to fracture the formation?

A. Yes, it does.

Ex. 2044, V. Rao Depo. at 78:22-79:1.

Paper No. 39

UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

WEATHERFORD INTERNATIONAL, LLC;
WEATHERFORD/LAMB, INC.;
WEATHERFORD US, LP; and WEATHERFORD
ARTIFICIAL L
Pe

PACKERS PLUS E

Pat

Inter Partes Review No. IPR2016-01509
Patent 7,861,774

PETITIO

Petition establishes and PO concedes that Thomson's multistage horizontal fracturing system and method is identical to the claimed features with one exception: Thomson was run in cased-hole instead of the claimed open-hole application. Petition at 55-

PO's detailed discussion of how Ellsworth allegedly fails to teach fracturing (POR at 53-55) is irrelevant as Ellsworth has not been relied upon for fracturing.

Paper 39, Petitioner Reply at 4, 15.

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

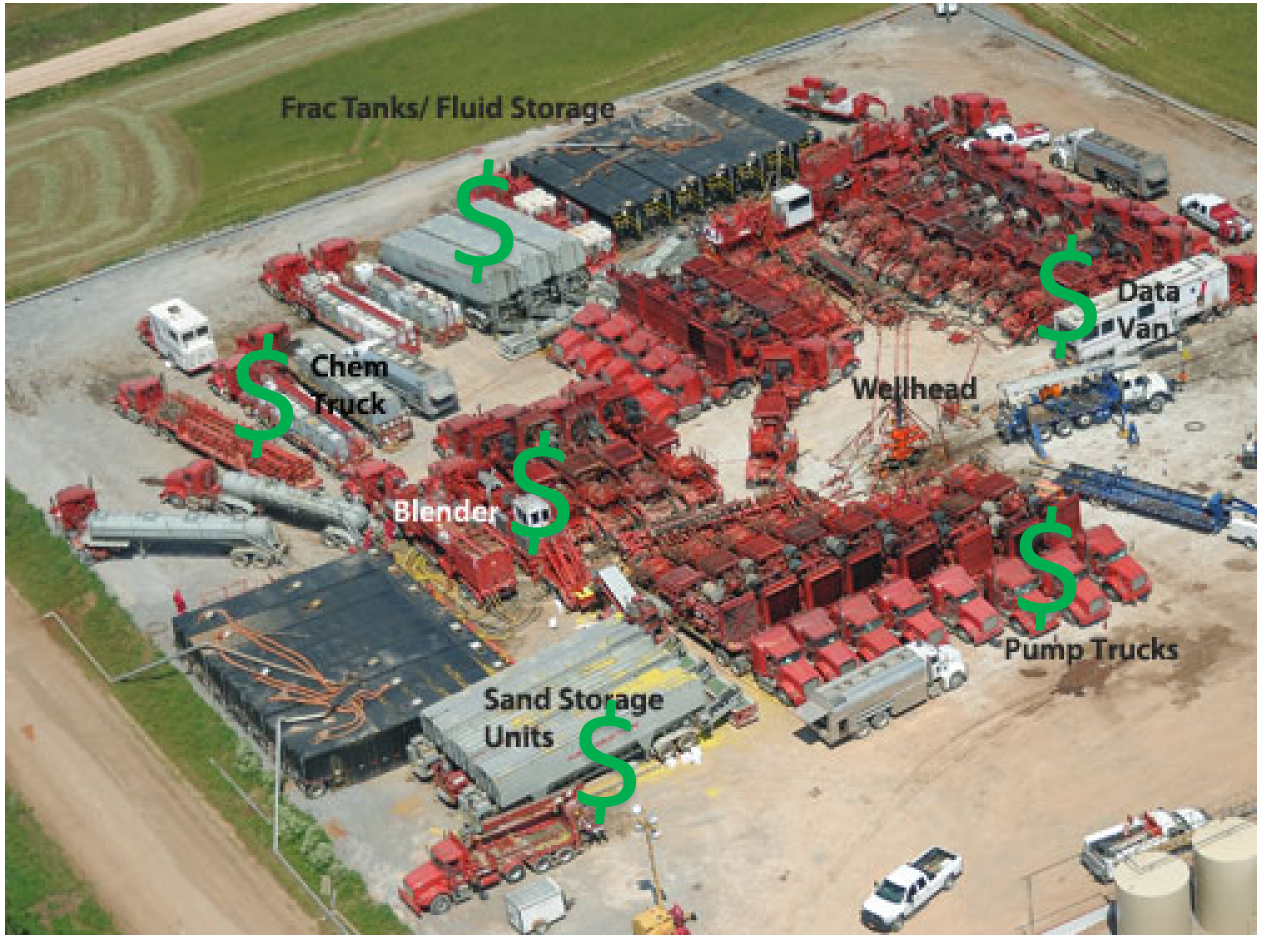
A. They don't go into it. As far as I can understand, **the prior wells in that platform had used casing and cementing and so -- and they were asked to improve the efficiency of the prior wells, so they continued to use what was being used.** I doubt it was a decision point.

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

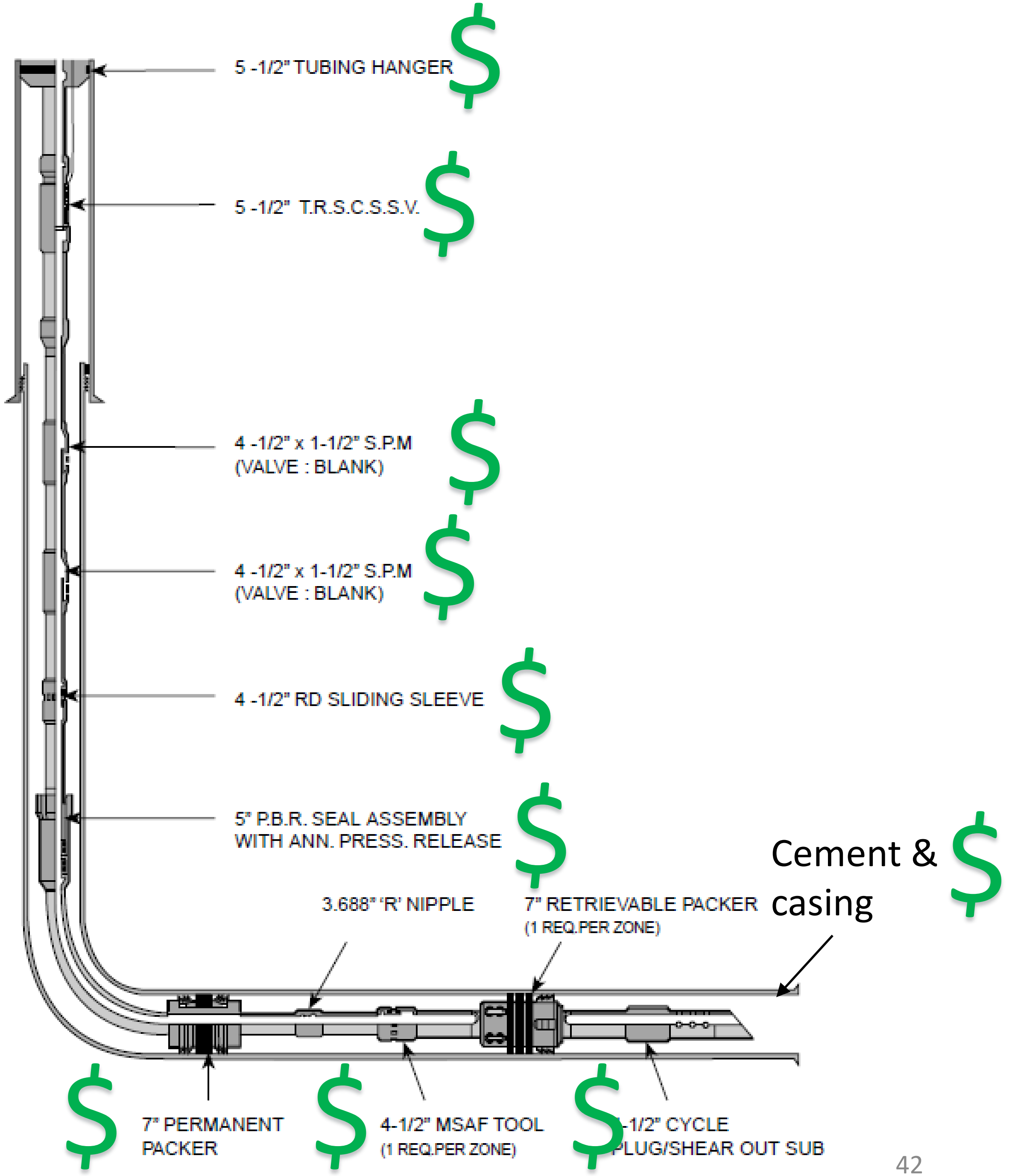
Petitioners must prove a motivation to remove a component.

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

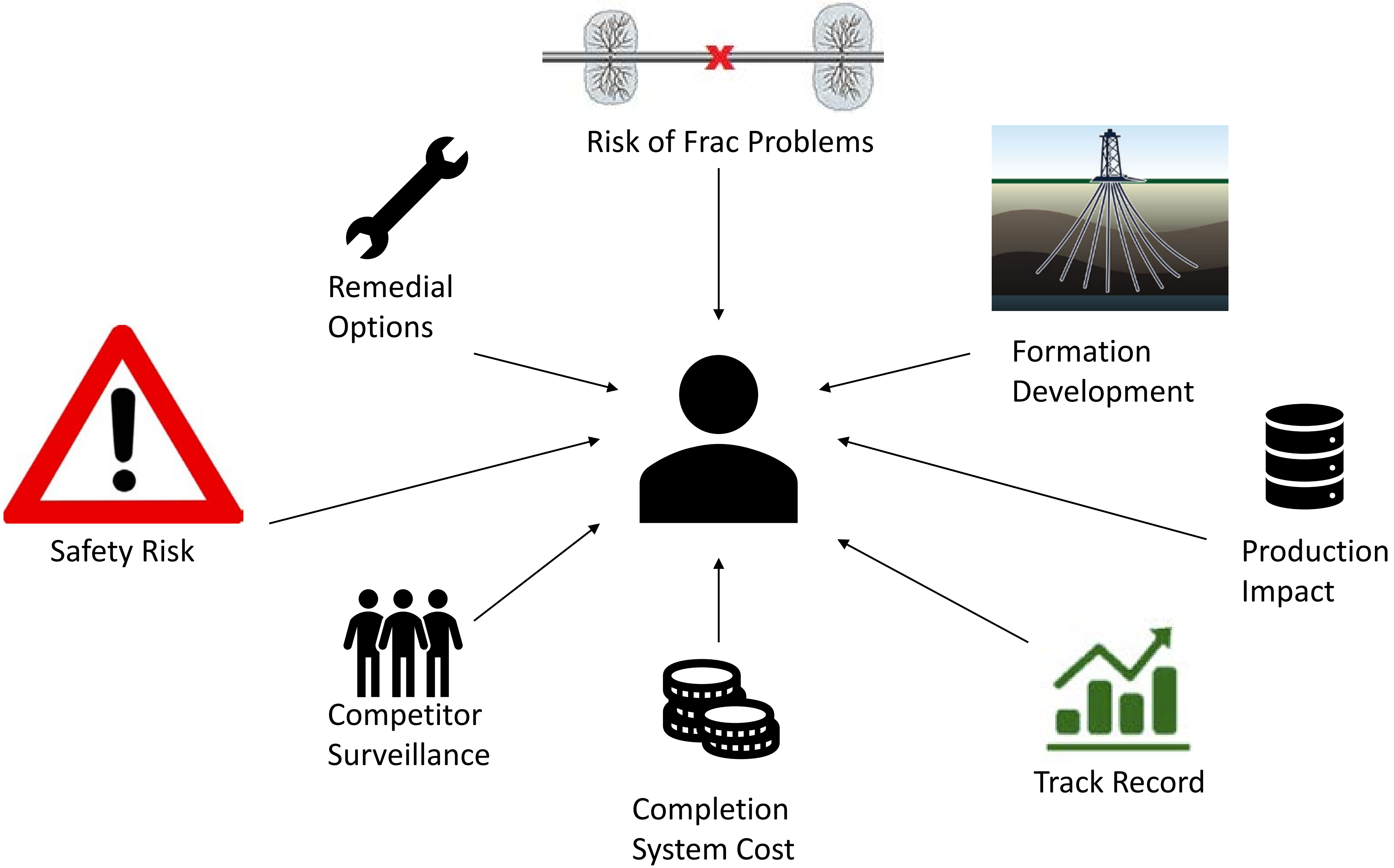
Amkor Tech., Inc. v. Int'l Trade Comm'n, 692 F.3d 1250, 1260 (Fed. Cir. 2012)



Frac Tanks/ Fluid Storage
$
Chem Truck
$
Data Van
$
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


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

US007571765B2

(12) **United States Patent**
Themig

(10) **Patent No.:** **US 7,571,765 B2**
(45) **Date of Patent:** **Aug. 11, 2009**

(54) **HYDRAULIC OPEN HOLE PACKER**

(76) Inventor: **Daniel Jon Themig**, 52 Glenhill Drive,

2,121,002 A 6/1938 Baker
2,618,340 A 11/1952 Lynd
2,715,444 A 8/1955 Fewel

(54) **HYDRAULIC OPEN HOLE PACKER**

(76) Inventor: **Daniel Jon Themig**, 52 Glenhill Drive, Cochrane, AB (CA) T4C 1G9

(65) Prior Publication Data

US 2008/0277110 A1 Nov. 13, 2008

3,154,940 A 11/1964 Loomis
3,158,378 A 11/1964 Loomis

--(73) Assignee: Halliburton Energy Services, Inc. Houston, TX (US)--

(Certificate of Correction)

(60) Provisional applic... 19, 2001, provisi... filed on Aug. 21, 2...

(51) **Int. Cl.**
E21B 23/06 (2006.01)
E21B 33/124 (2006.01)

(52) **U.S. Cl.** **166/191**; 166/50; 166/313; 277/337

(58) **Field of Classification Search** 166/191, 166/50, 245, 313, 387, 185, 186; 277/322, 277/337, 342, 338
See application file for complete search history.

(56) **References Cited**

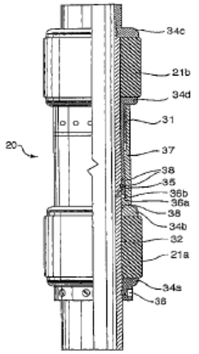
U.S. PATENT DOCUMENTS

1,956,694 A * 5/1934 Parrish 277/342

(57) **ABSTRACT**

A tubing string assembly is disclosed for fluid treatment of a wellbore. The tubing string can be used for staged wellbore fluid treatment where a selected segment of the wellbore is treated, while other segments are sealed off. The tubing string can also be used where a ported tubing string is required to be run in in a pressure tight condition and later is needed to be in an open-port condition.

49 Claims, 9 Drawing Sheets



Ex. 2095
IPR2016-01509

36. A Well system, comprising:

a packer set in a horizontal open borehole, the packer including spaced apart first and second packing elements on a single generally tubular mandrel,

Wherein the packer further comprises a hydraulically actuated setting mechanism positioned between the first and second packing elements.

Ex. 2095

Paper 32, POR at 19

NO. CV44964

HALLIBURTON ENERGY SERVICES, INC. and HALLIBURTON GROUP CANADA §

Plaintiffs, §

v. §

PACKERS PLUS ENERGY SERVICES, INC.; PACKERS PLUS ENERGY SERVICES, INC. USA; PACKERS PLUS ENERGY SERVICES (U.S.A.) LIMITED PARTNERSHIP; DANIEL THEMIG; PETER KRABBEN; and KENNETH PALTZAT §

Defendants. §

FIRST SUPPLEMENTAL EXPERT REPORT OF WILLIAM O. BERRYMAN

Ex. 2094
IPR2016-01509

b) The Dresser Packer in the StackFRAC System

The Dresser packer could not perform the function of the RockSeal in the StackFRAC system. It is a cased-hole tool and is not designed for use in open-hole applications. Also, because it has only a single element package, one of the largest benefits provided by the RockSeal, redundant sealing systems, cannot be supplied by this packer.

As stated, my opinion is that claim 44 of the '505 patent and claim 26 of the '863 application require the RockSeal Invention. The Dresser packer in the '901 patent could not meet the limitations of either of those claims because it does not contain multiple spaced apart packing elements and because the hydraulic actuation mechanism is not located between the spaced-apart packing elements, among other deficiencies.

Ex. 2094, Halliburton expert report form prior litigation at 31

Paper 32, POR at 19

WEATHERFORD INTERNATIONAL, LLC, et al.

EXHIBIT 1012

WEATHERFORD INTERNATIONAL, LLC, et al.
v.
PACKERS PLUS ENERGY SERVICES, INC.

Expert Report

Re: Halliburton Energy Services, Inc. and Halliburton Group Canada v. Packers Plus Energy Services, I
No. CV-44,964
In the 238th Judicial District Court of Midlan

Prepared for

Packers Plus Energy Services, I
&
Counsel

By

Kevin Trahan

Trahan Oilfield Consulting, LLC

April 27, 2007

ATTORNEYS EYES ONLY- RESTRICTRED 1

RESTRICTED – ATTORNEYS' EYES ONLY HES-PP_000074

and in the body of this opinion, I consider myself qualified to provide detailed responses to each of the opinions reached by Berryman in his report, as well as other allegations made by Halliburton in this lawsuit. Those areas include, but are not limited to:

4. The question whether the Rockseal packer was a novel, patentable invention;

Ex. 1012, Kevin Trahan (Packers Plus) expert report form prior litigation at 4

Paper 32, POR at 19

WEATHERFORD INTERNATIONAL, LLC, et al.

EXHIBIT 1012

WEATHERFORD INTERNATIONAL, LLC, et al.
v.
PACKERS PLUS ENERGY SERVIC

Expert Report

Re: Halliburton Energy Services, Inc. and Hallibu
v. Packers Plus Energy Services, Inc.
No. CV-44,964
In the 238th Judicial District Court of Midland

Prepared for

Packers Plus Energy Services, Inc.
&
Counsel

By

Kevin Trahan

Trahan Oilfield Consulting, LLC

April 27, 2007

ATTORNEYS EYES ONLY- RESTRICTRED 1

Mr. Berryman also states on page 37 of his report that a tool that uses Rockseal features in combination with applying that tool in open hole or horizontal open hole may be patentable. Cased hole tools, including packers, have been used in open hole applications for many years. In my opinion use of a tool with Rockseal type features in open hole does not pass the patentability standard of novelty or nonobviousness. The open hole application of tools that were originally designed for cased hole has been common place in the industry since I began working in the industry in 1992. There is nothing novel or nonobvious about such an application.

RESTRICTED – ATTORNEYS' EYES ONLY HES-PP_000074

Ex. 1012, Kevin Trahan (Packers Plus) expert report form prior litigation at 52-52

Paper 32, POR at 19

Where the uncased wellbore might make a difference, such as for packers, **persons of ordinary skill in the art readily understood the considerations of using a cased hole tool in an open hole well and could readily discern when it was advisable to use a cased hole tool in open hole and when it was not.**

Ex. 1007, Rao Decl. at 32.

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.

Dr. Ali Daneshy – Fracturing Experience

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

Dr. Vikram Rao – Fracturing Experience

Q. How many multistage frac jobs have you personally designed throughout your entire career?

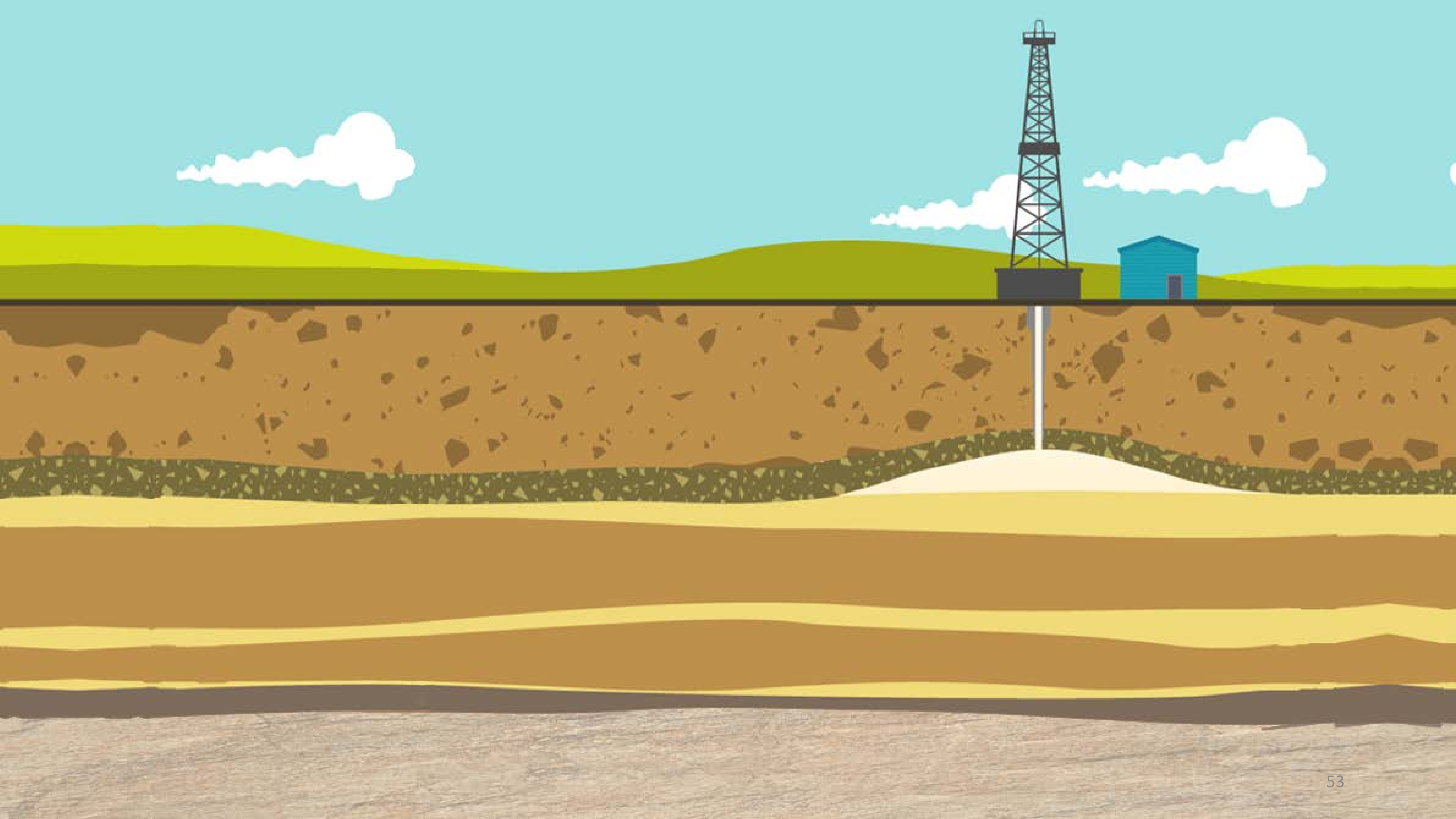
A. As I mentioned to you already, any -- **any fracturing job of any type, multistage or otherwise, would have been designed by people in my company** who either indirectly or directly report to me.

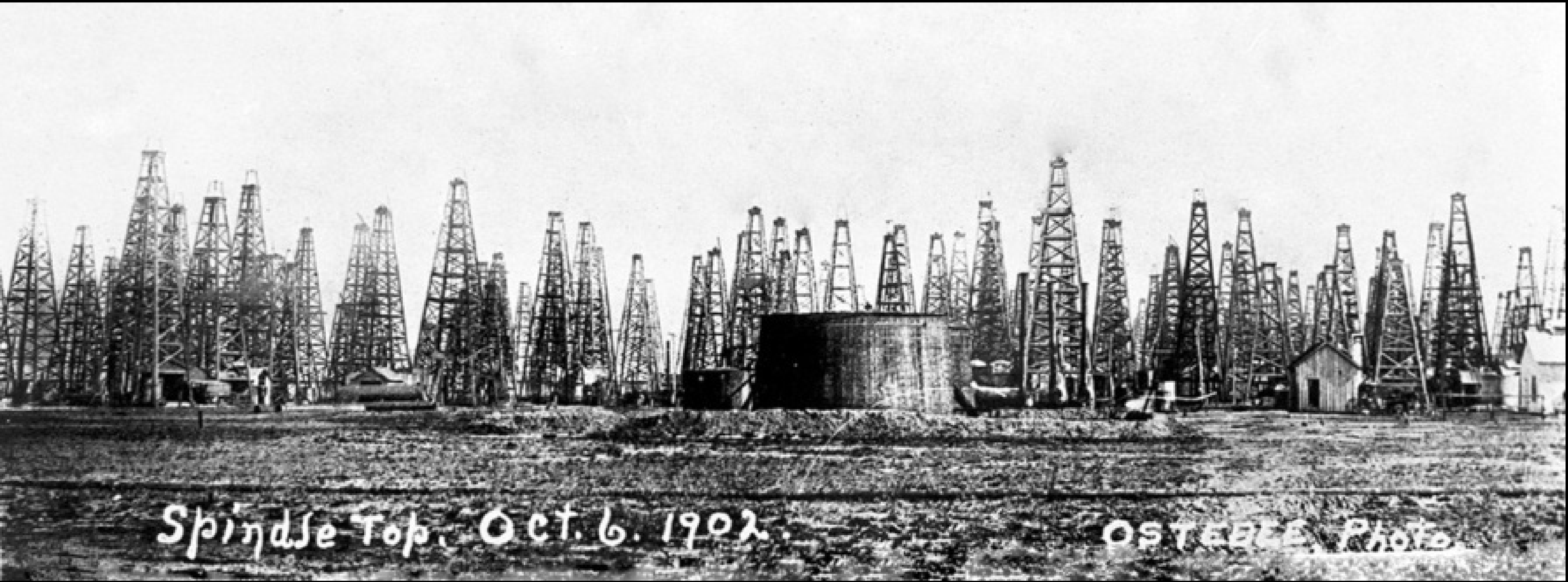
[. . .]

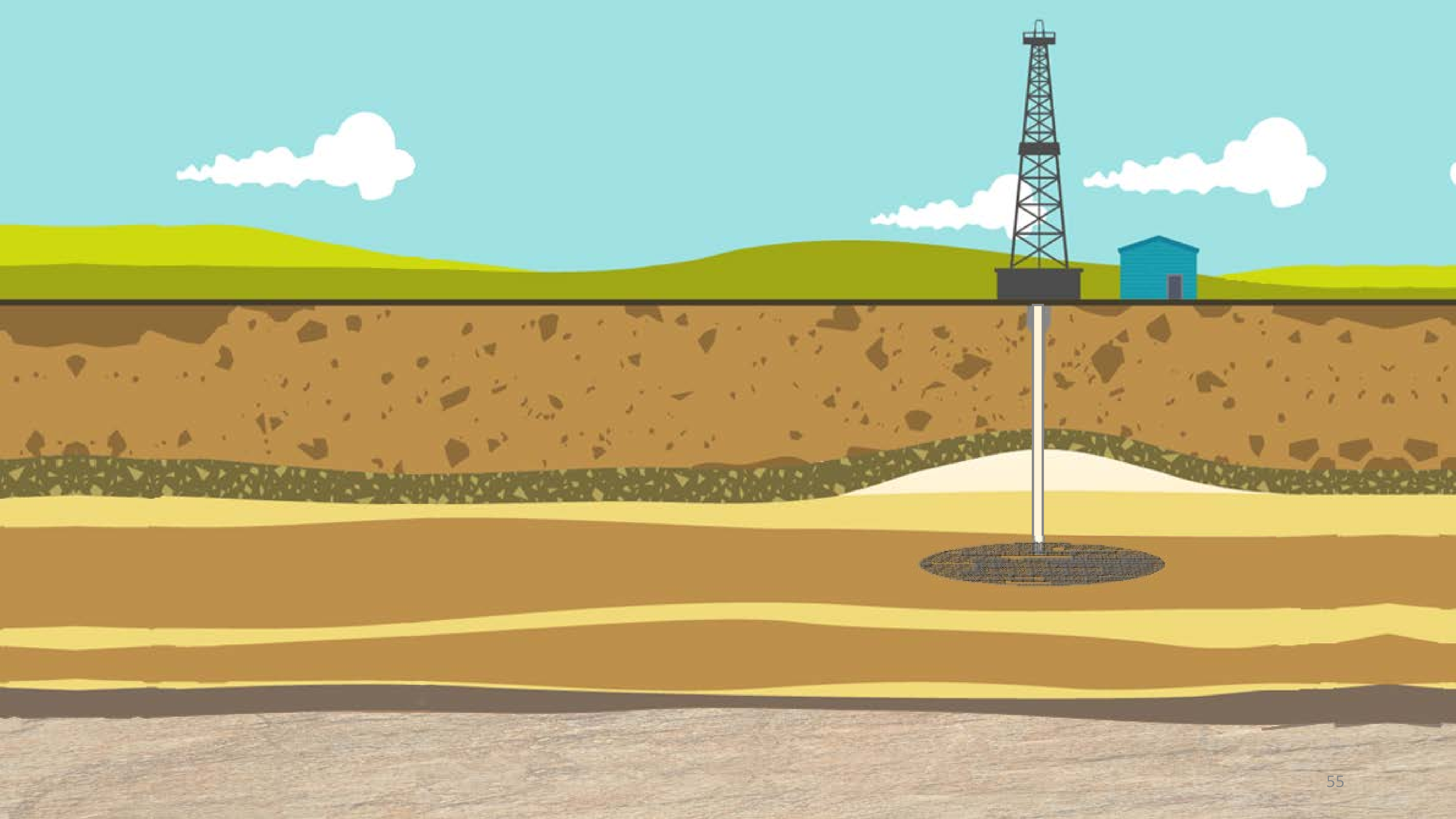
Q. **And you were in charge of the business unit at Halliburton that designed frac jobs for wells?**

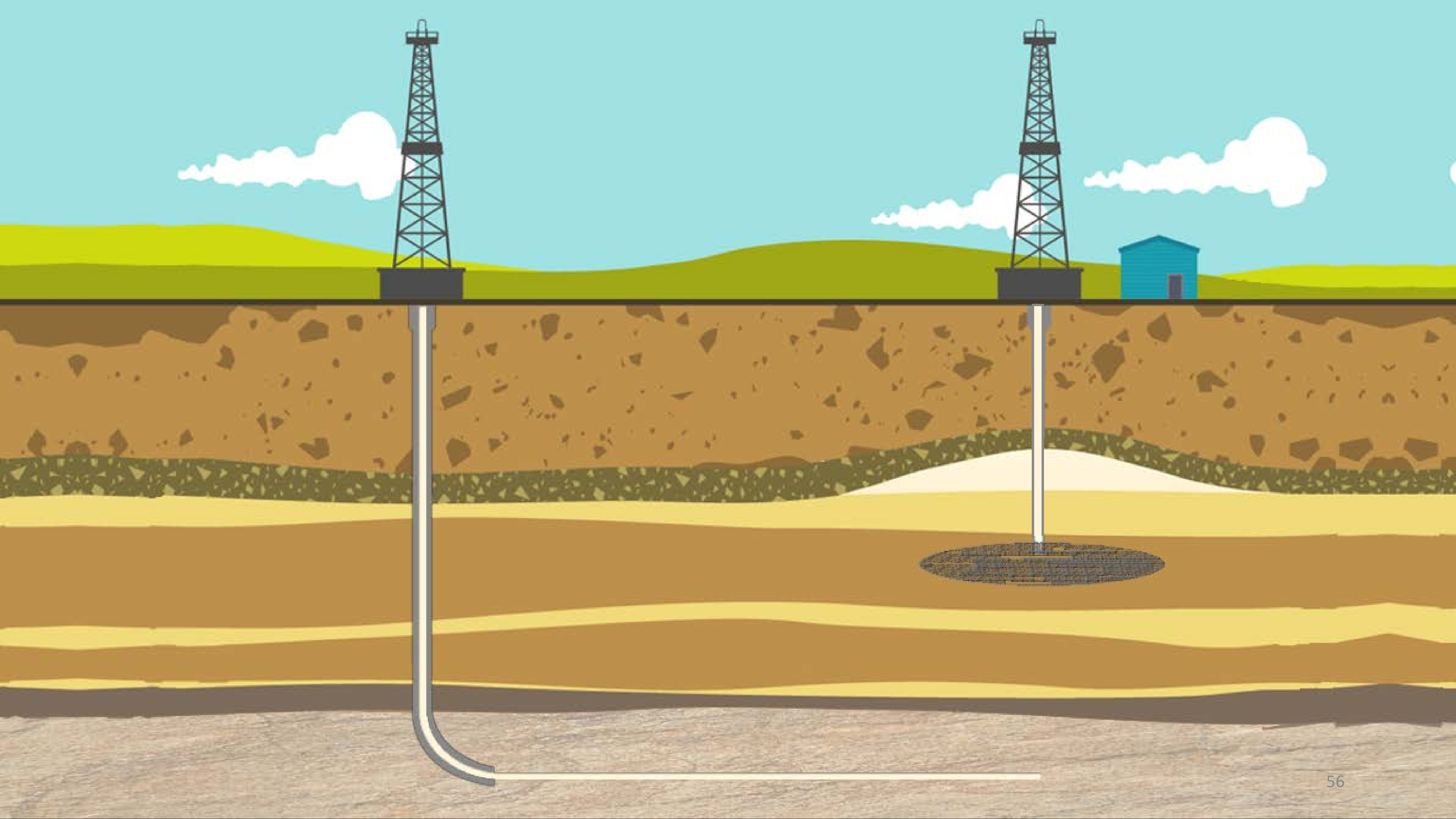
A. **No, not**. I was in charge of technology.

Ex. 2101, V. Rao Depo. at 6:22-7:13.




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.

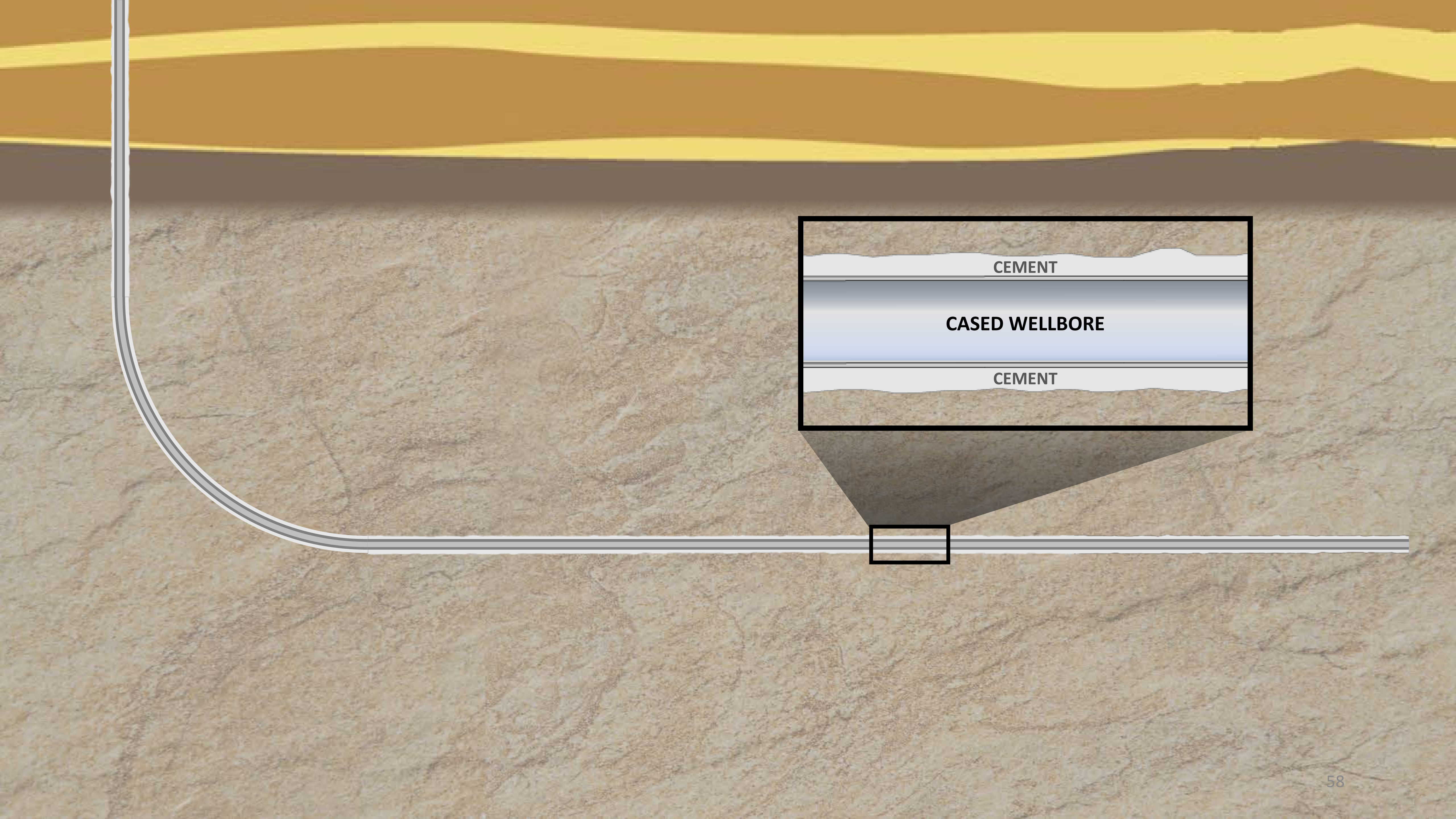
In order to explain more clearly, consider the simple derivation of the Darcy flow equation for an ideal liquid, for a vertical well (1), written in oilfield units. This equation simply states that the production rate (q) is directly proportional to the applied drawdown (Δp), the reservoir thickness (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).

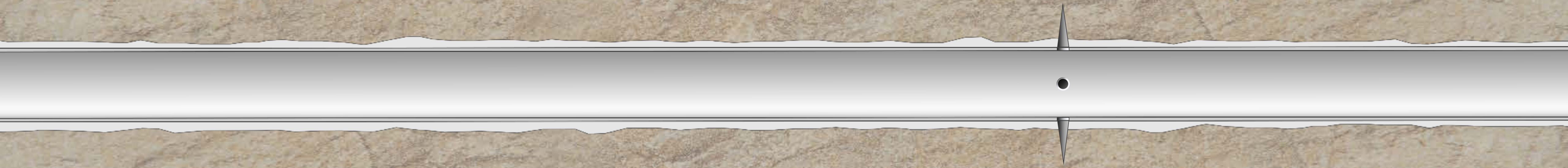
$$q = \frac{kh}{141.2B\mu} \cdot \frac{\Delta p}{\ln\left(\frac{r}{rw}\right)} \qquad \ldots (1)$$

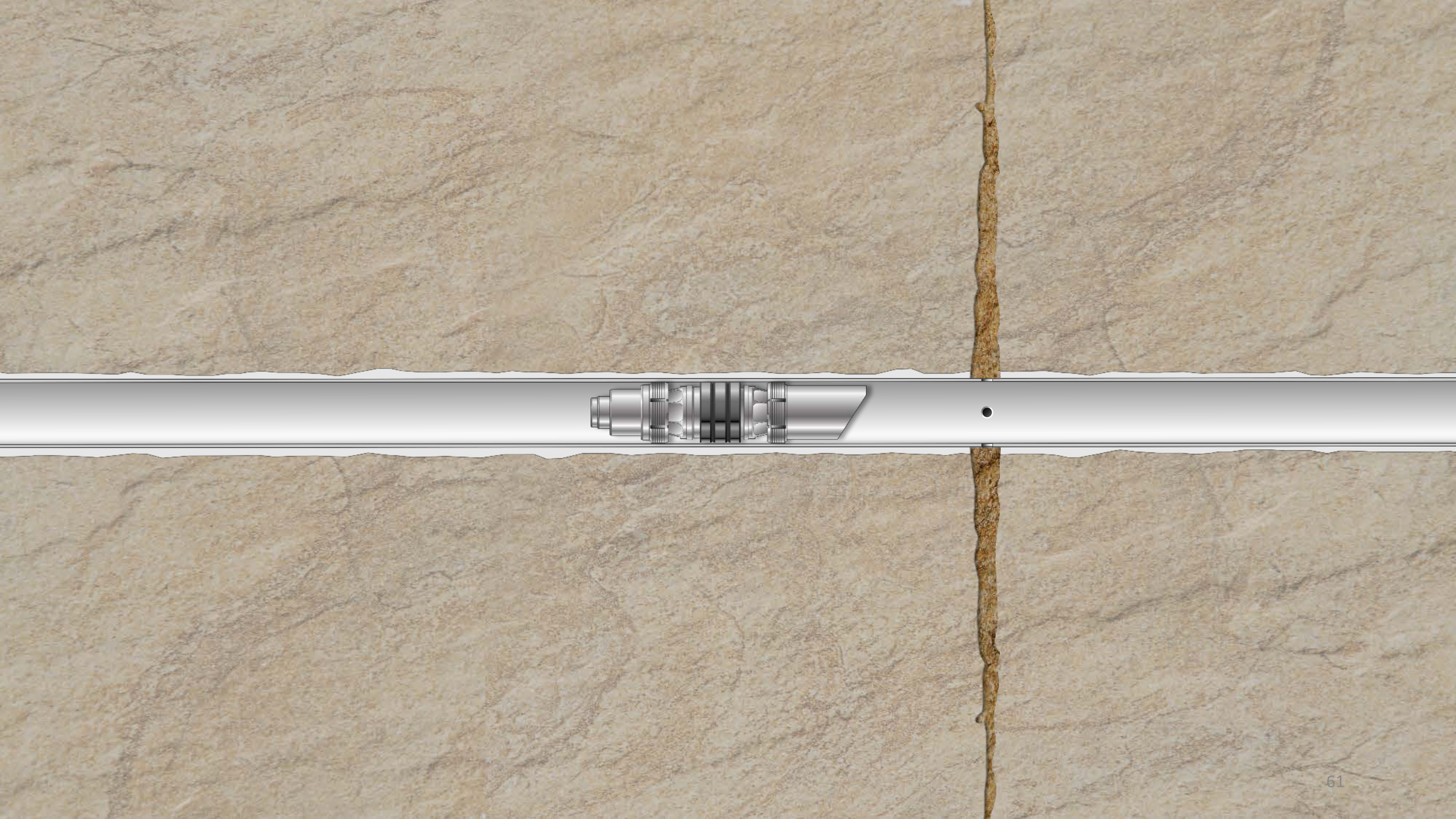
Exhibit 2001
IPR2016-00598

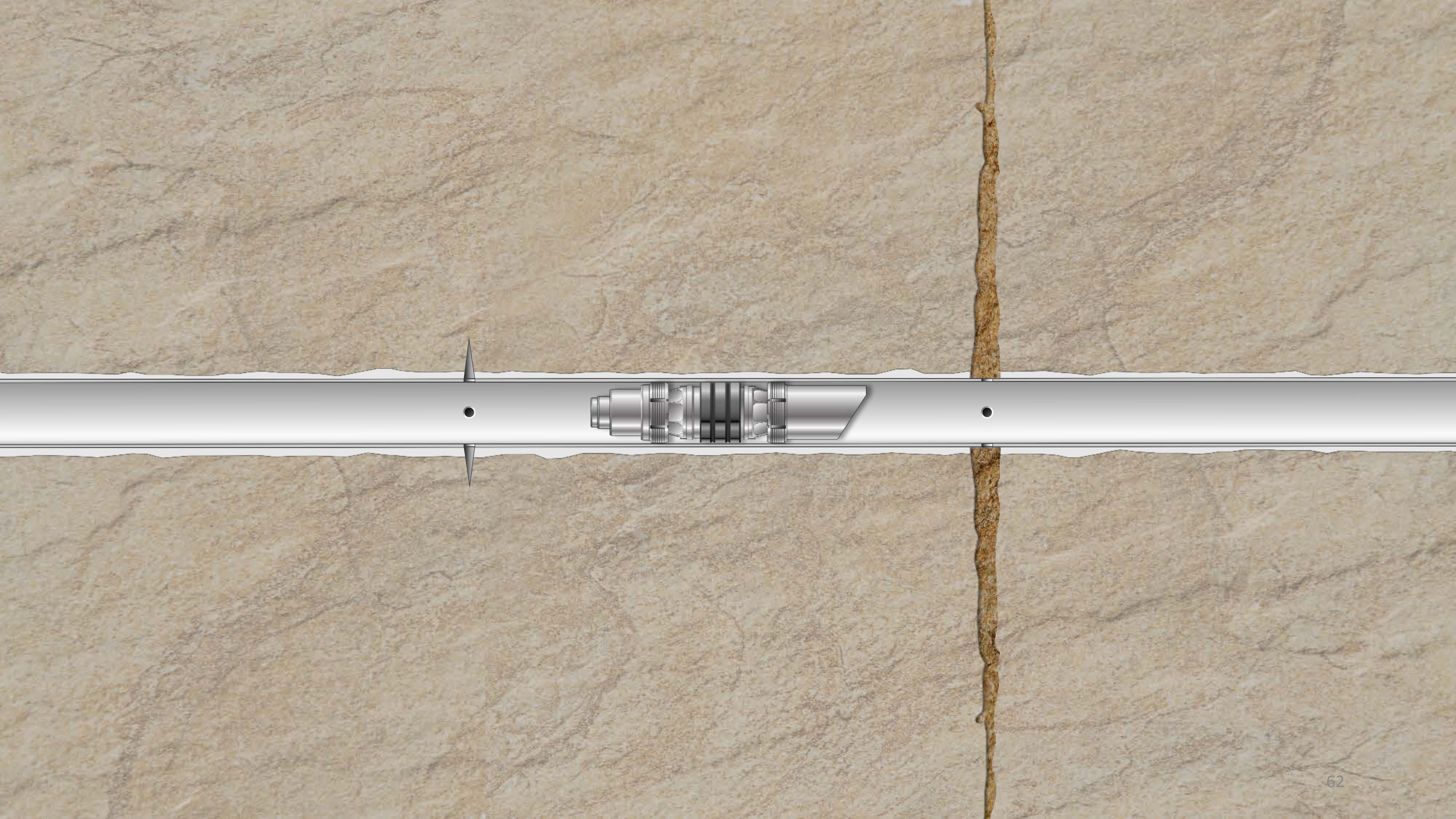
The P&P approach was the initial lower completion methodology that allowed the effective deployment of multi-fracture treatments in horizontal wells . . .

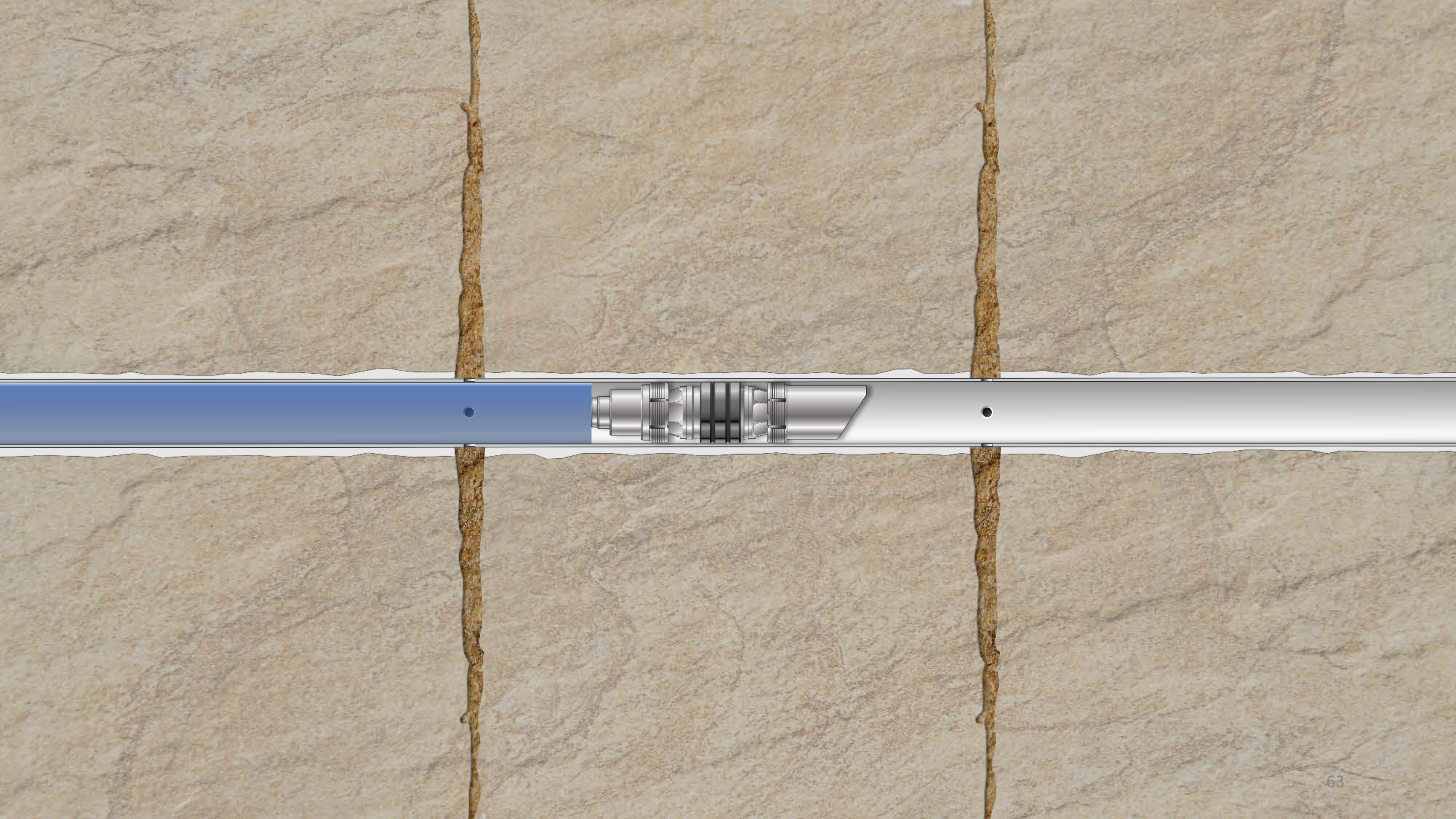
Ex. 2001 at 5, A. Casero, Open Hole Multi-Stage Completion System in Unconventional Plays: Efficiency, Effectiveness and Economics, SPE 164009 (2013); see also Ex. 2050, McGowen Decl. at 26; Paper 51, POR at 13-15.

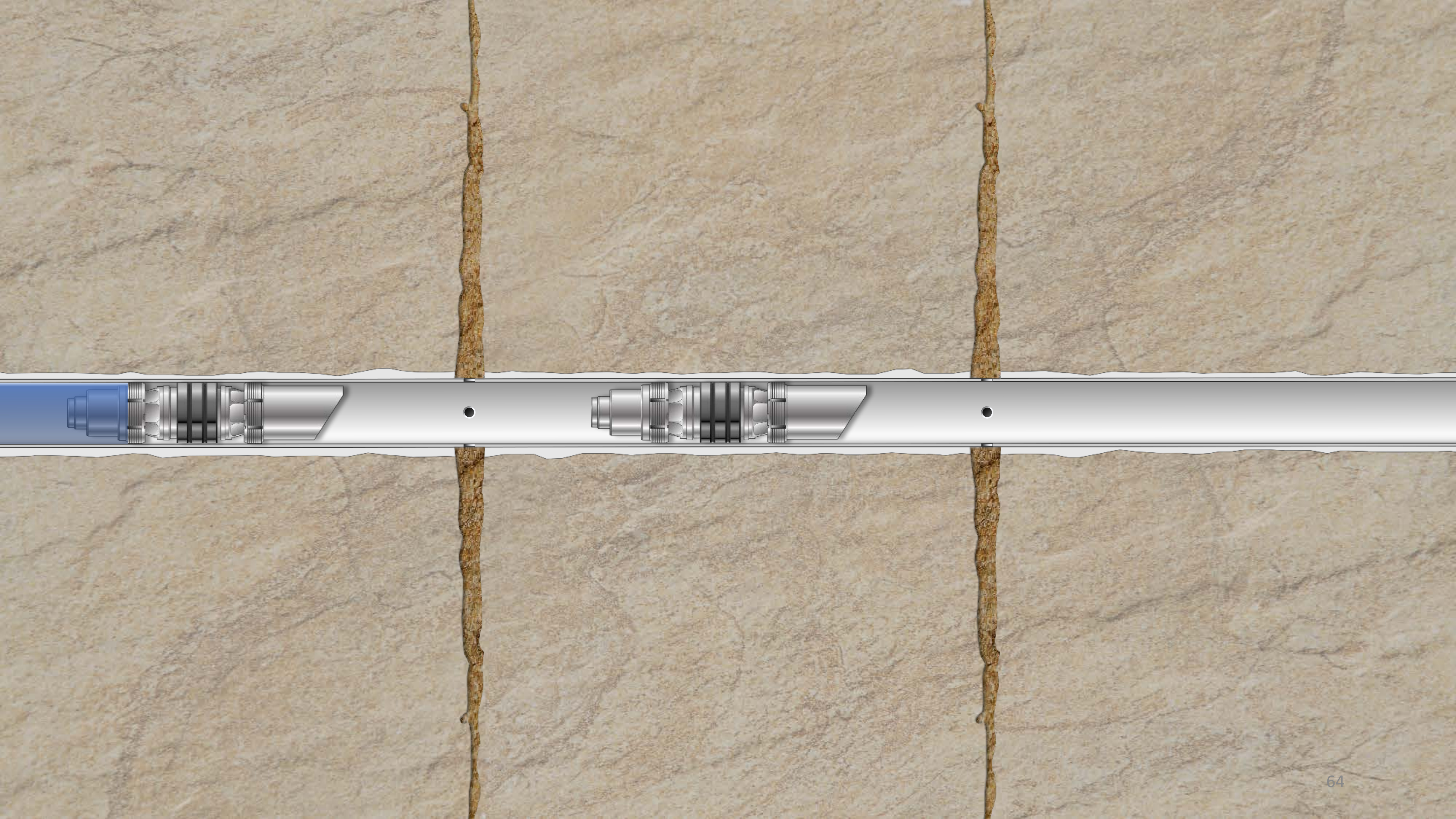

CEMENT
CASED WELLBORE
CEMENT

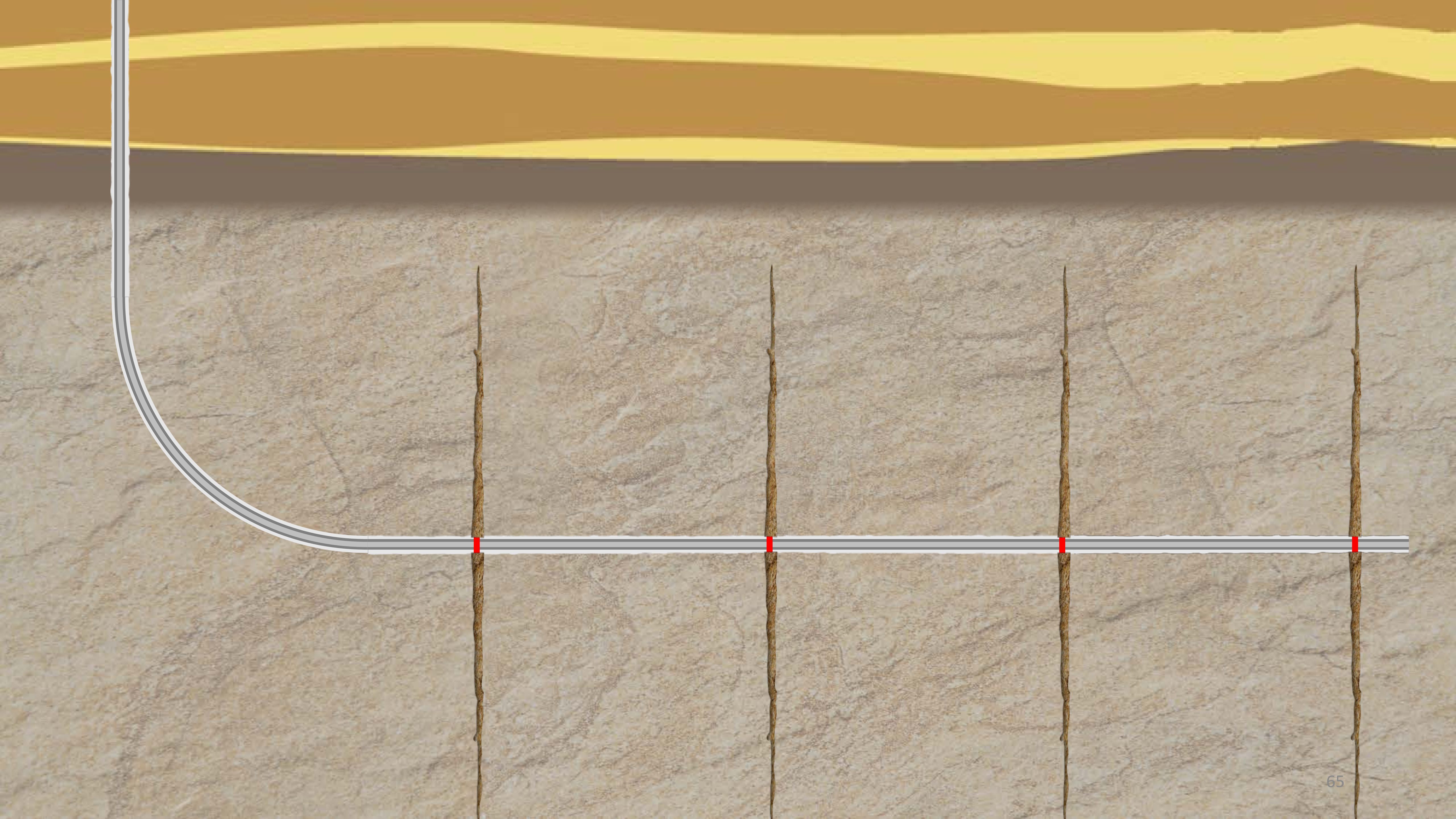


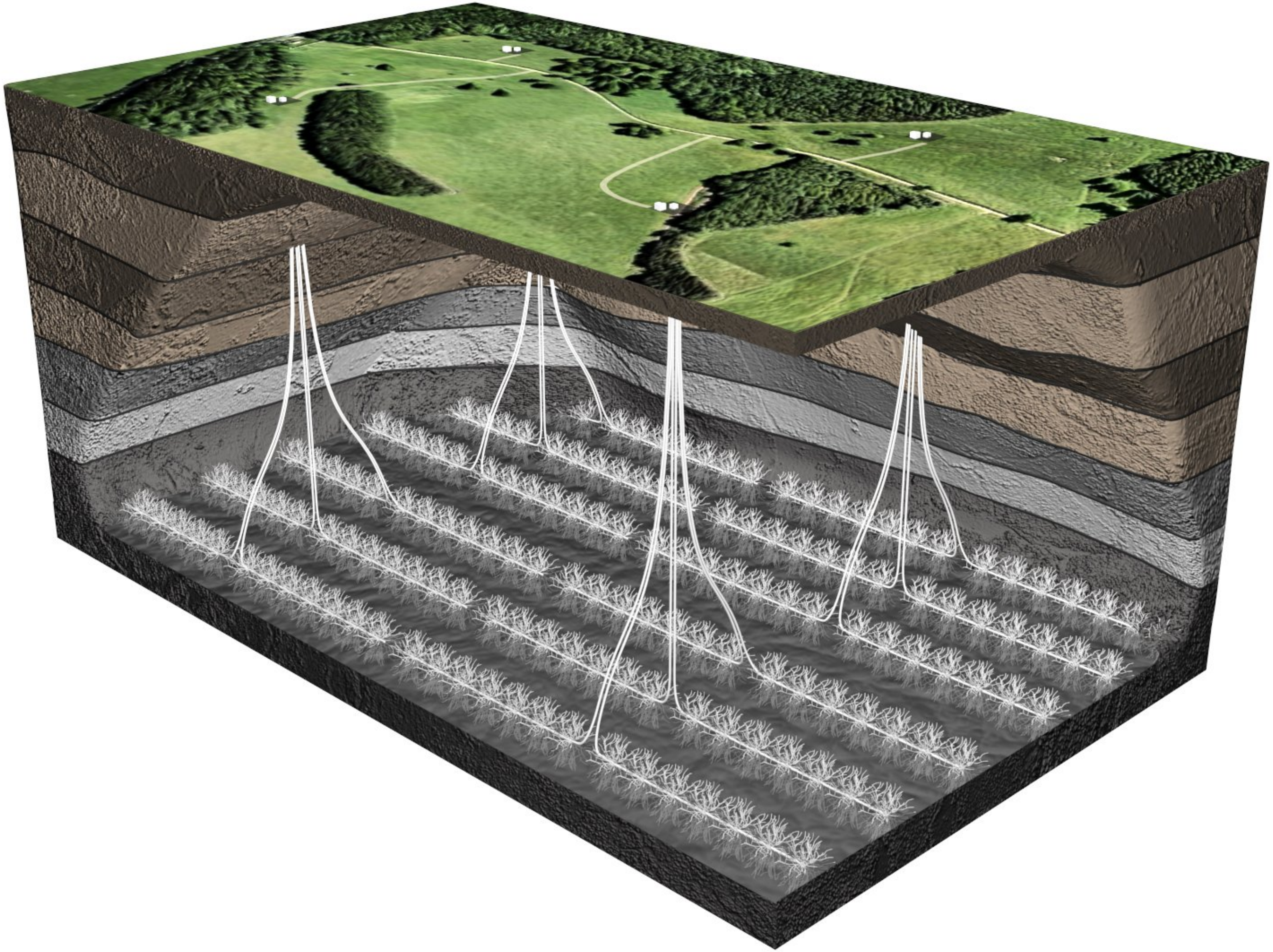










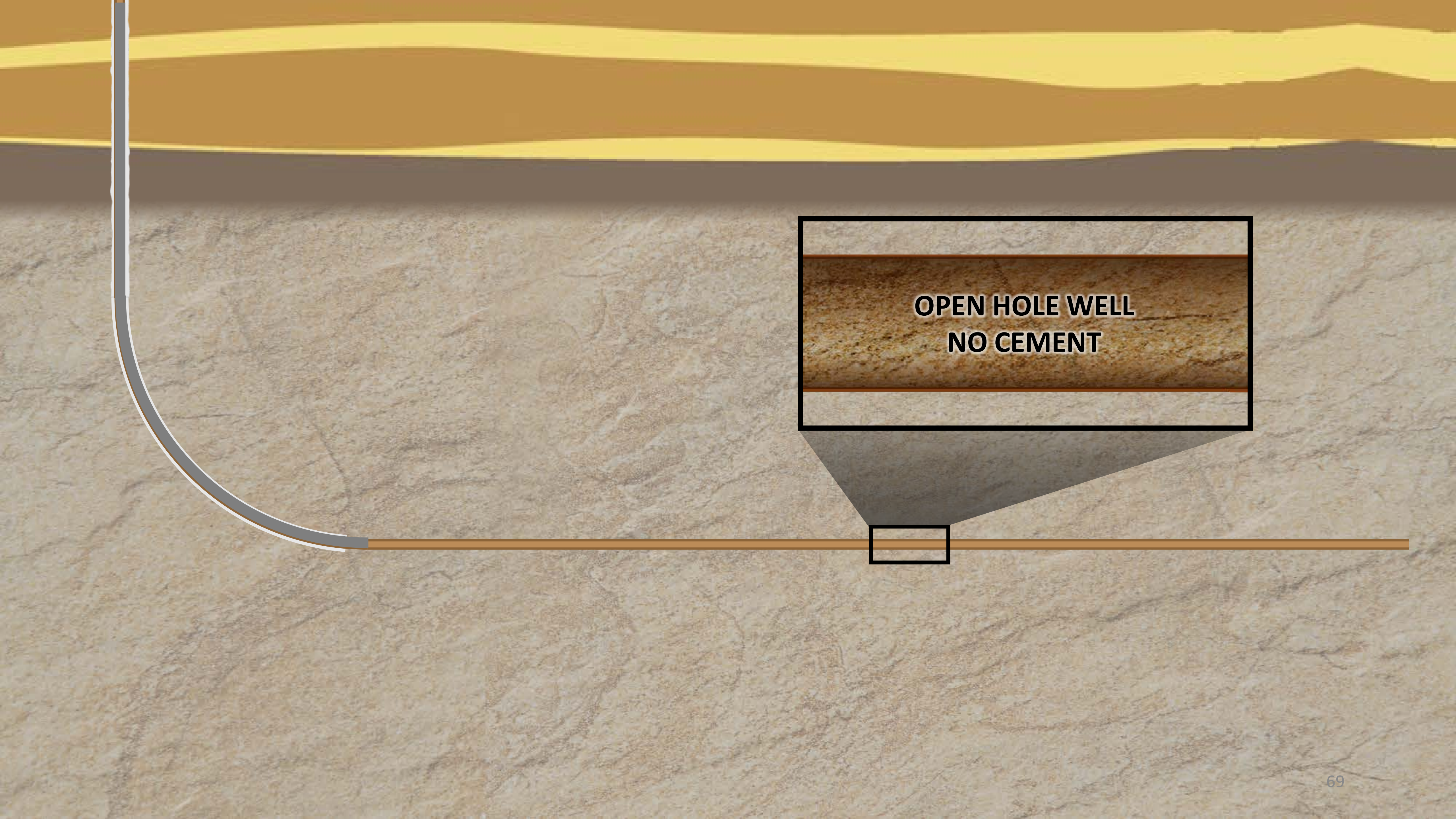


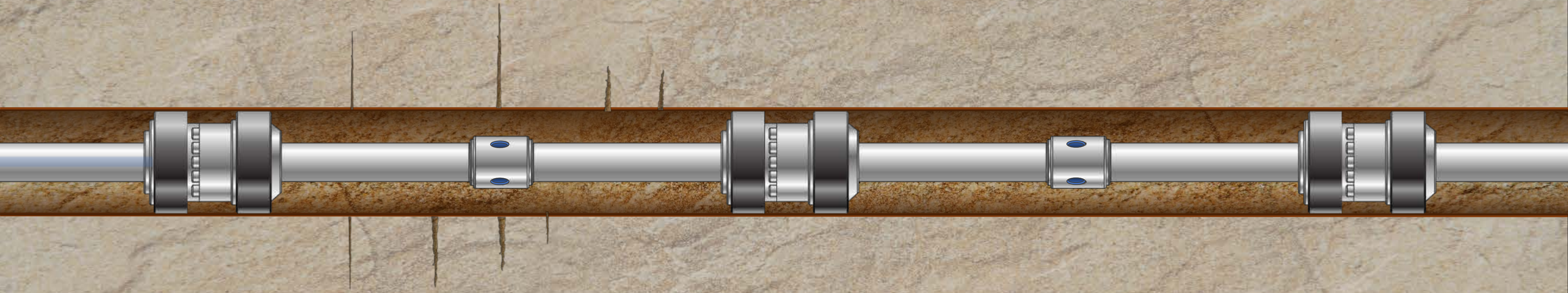
Q. Why does that difference matter?

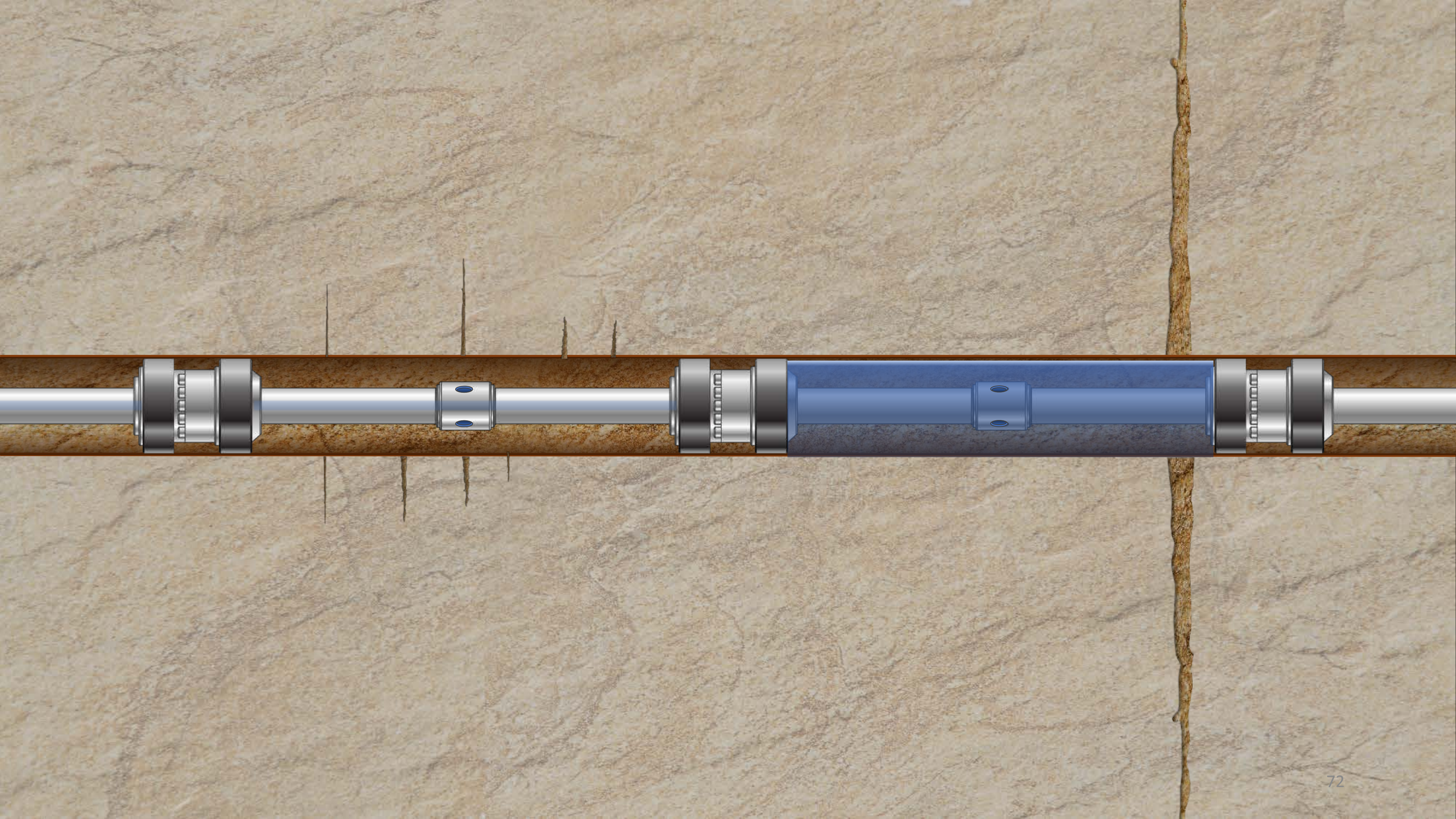
MR. GARRETT: Objection, form.

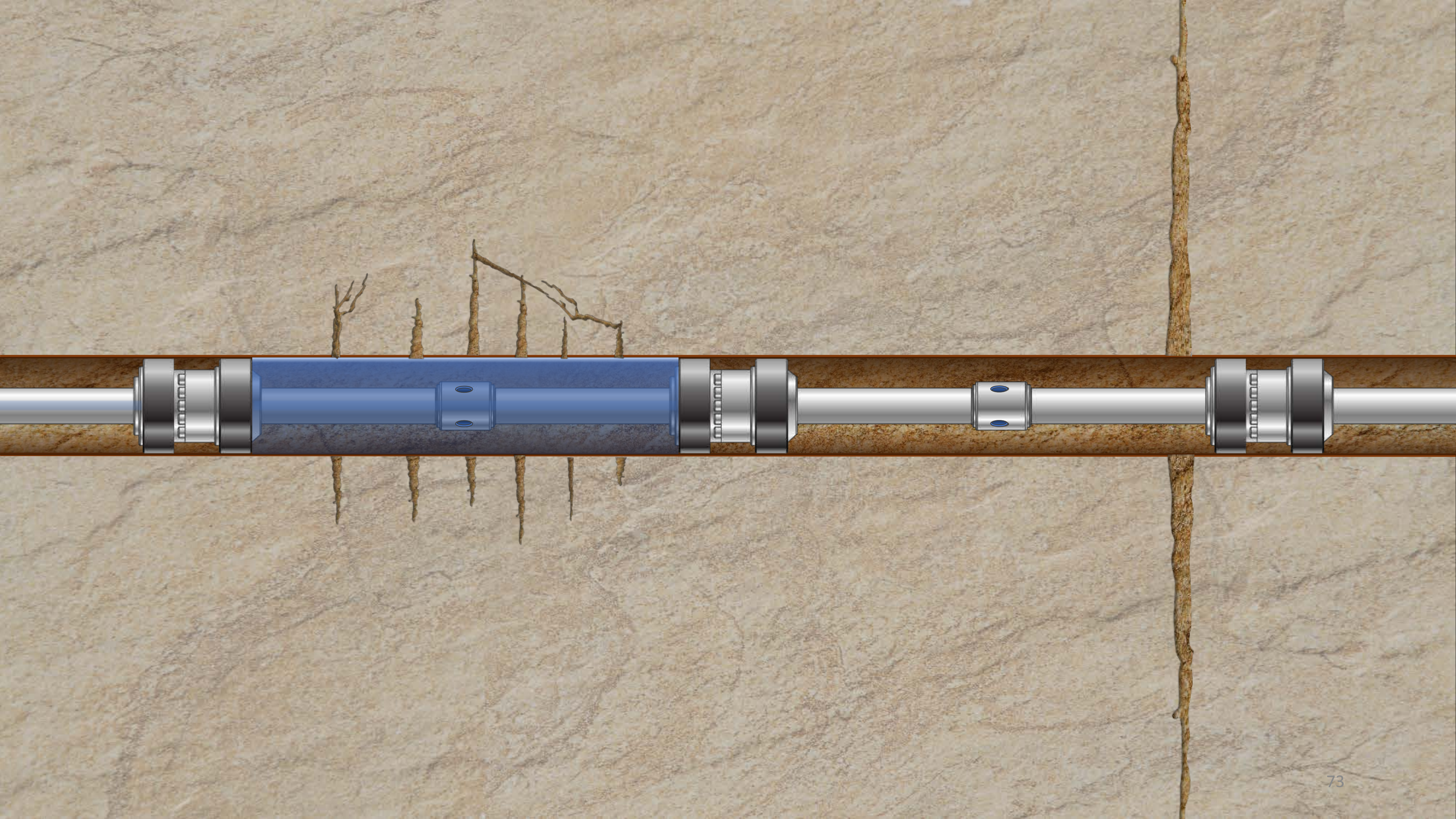
A. Because the location of the fracture influences [well] productivity and how the reservoir is being depleted. **You want uniform depletion of reservoir fluid so that you get as much of the oil or gas out of the formation; and so for that, it is better to know more accurately where the fractures are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

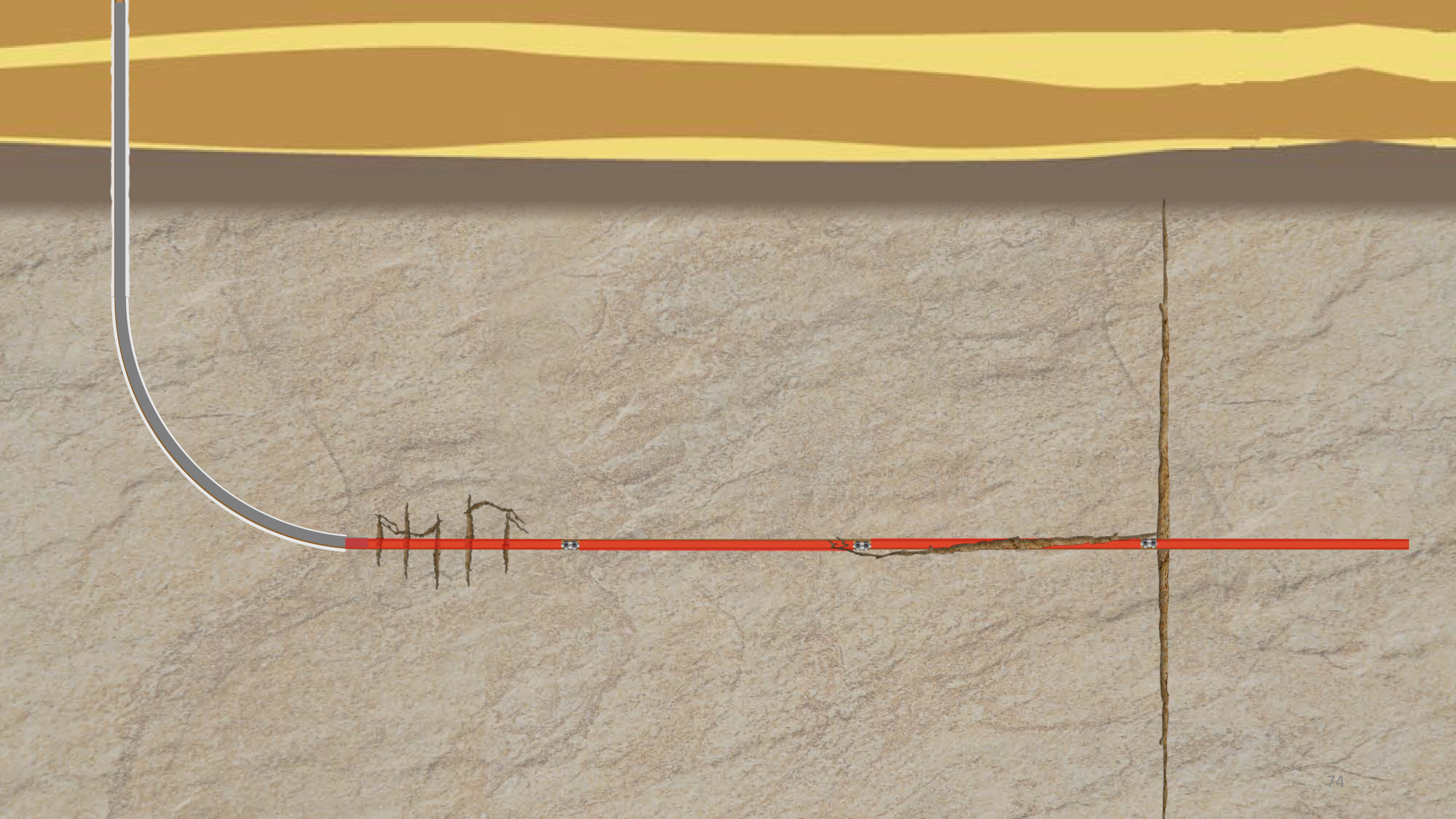
Ex. 2016, A. Daneshy Depo. at 21:13-20

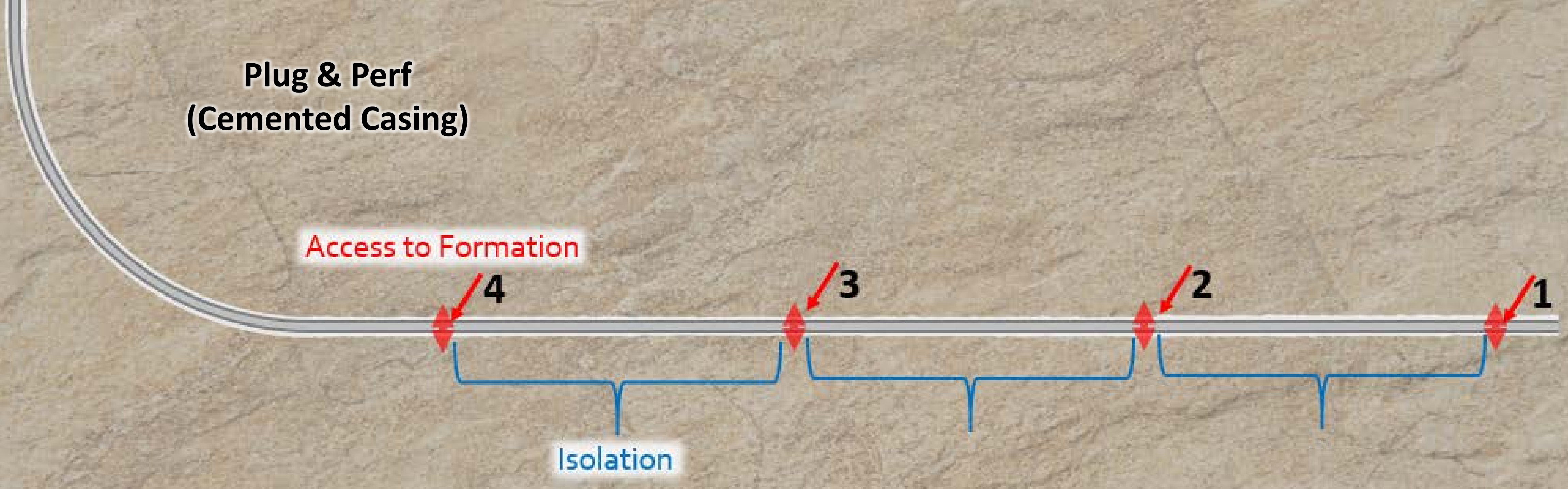

OPEN HOLE WELL
NO CEMENT

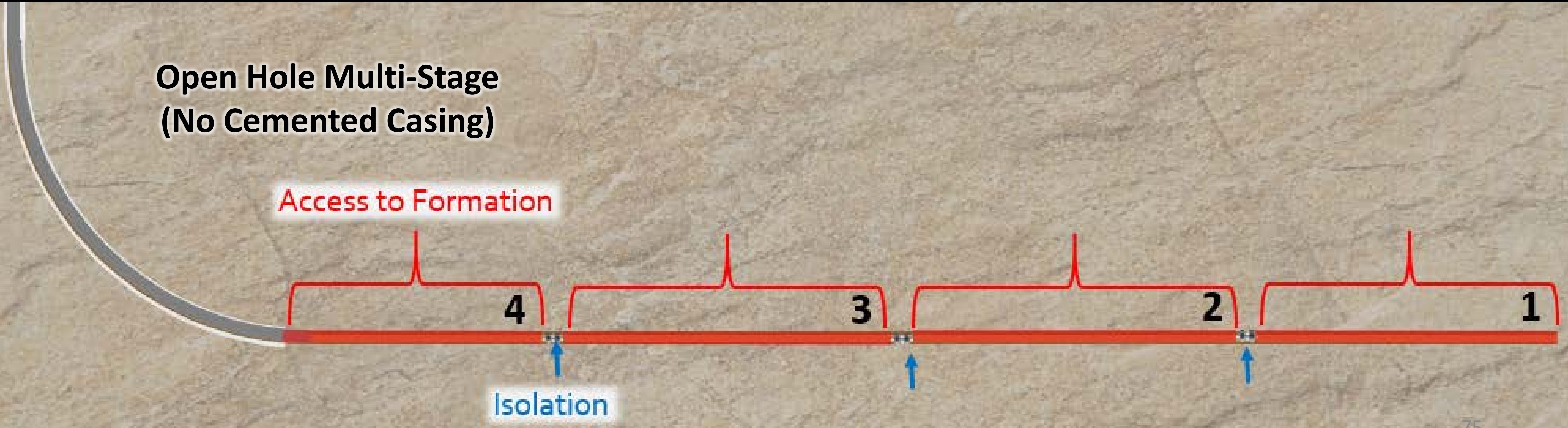


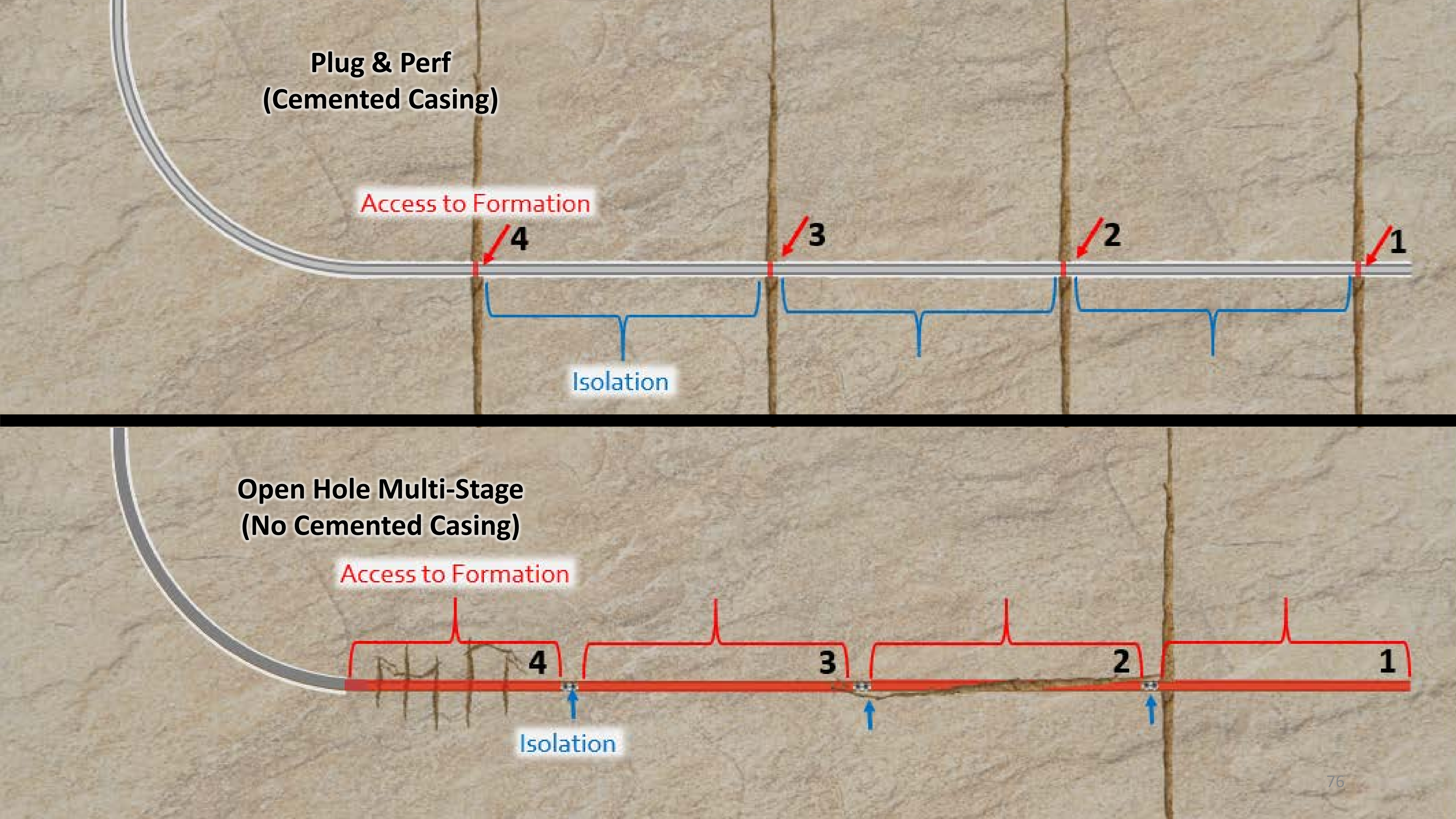







Plug & Perf
(Cemented Casing)
Access to Formation
4
3
2
1
Isolation


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

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. 2016, 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. 2016, A. Daneshy Depo. at 30:6-14

Q. Do you agree with Dr. Daneshy's testimony in that paragraph [on pages 29-30]?

MR. SHAPIRO: Same objections.

A. No.

Ex. 2044, V. Rao Depo. at 54:8-11.

This bit about what fractures do in the formation, a practitioner of ordinary skill would be relatively unconcerned and would have no knowledge, and if there were papers written about something like that, he or she would be unlikely to want to read them.

Ex. 2044, V. Rao Depo. at 50:11-16.

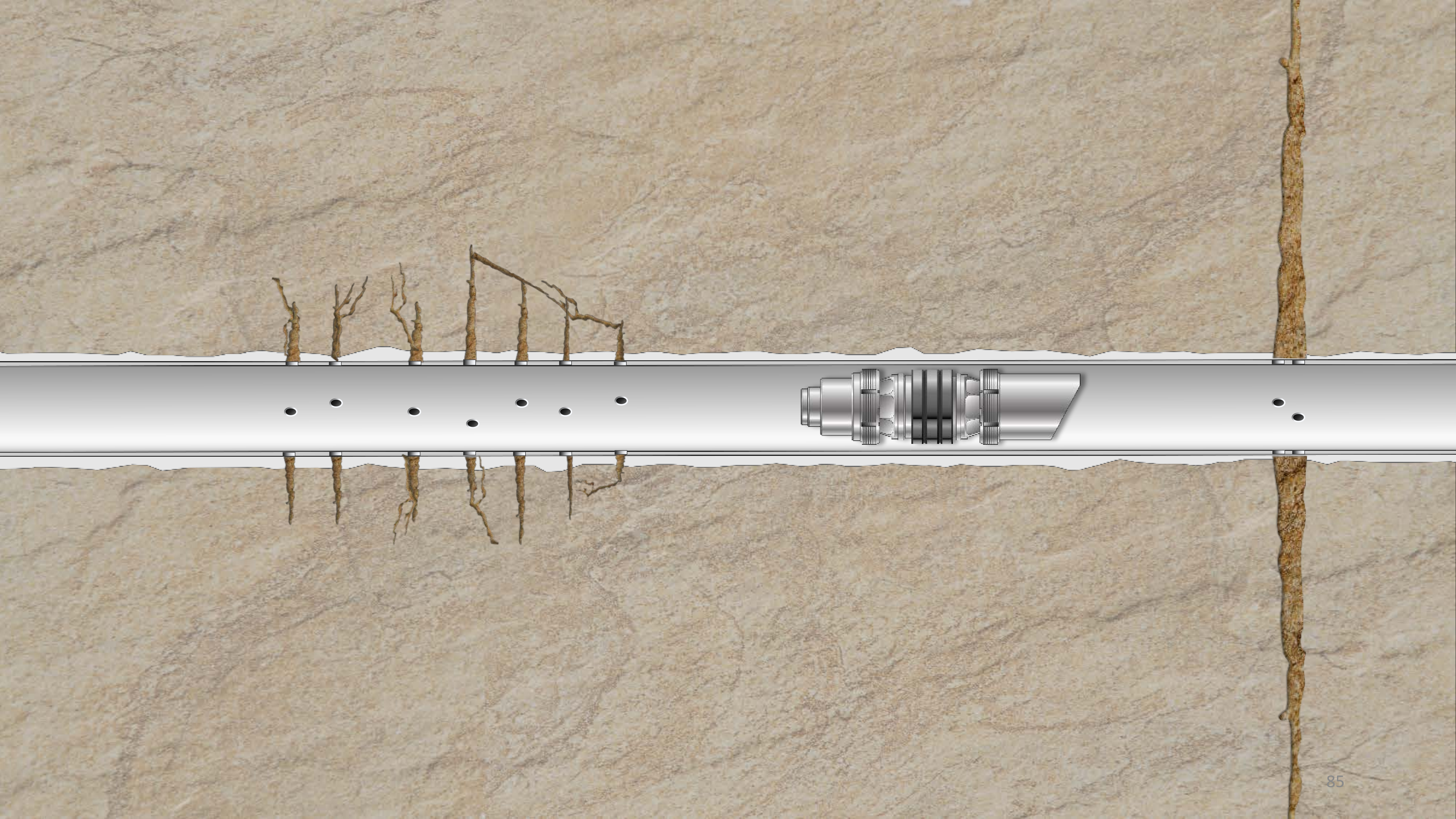
Q. And they have the burden of proving obviousness, right?

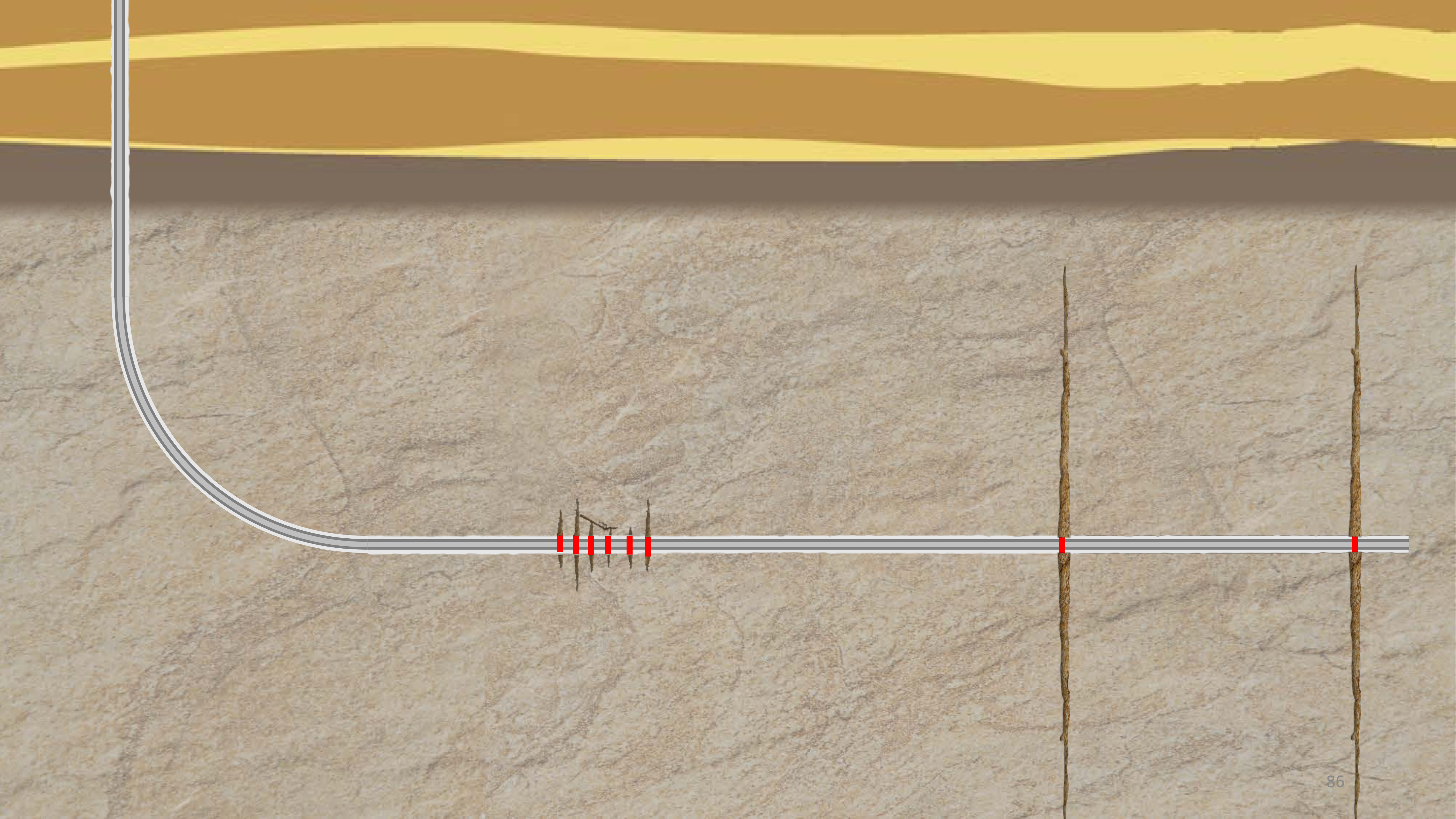
A. The -- the burden is slightly slanted in -- in this favor of the -- of us, yes. When I say us, I mean Weatherford. **I'm merely a hired gun.**

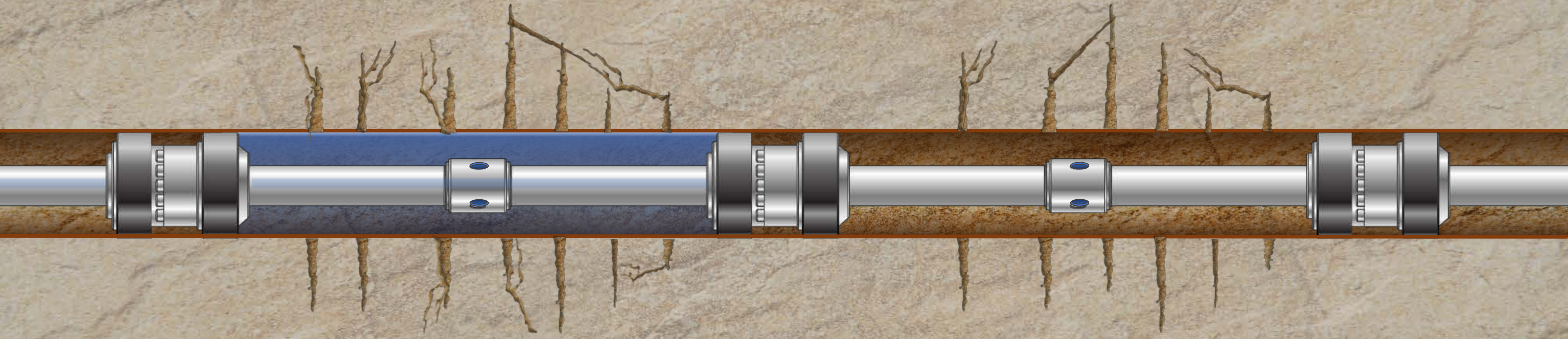
Ex. 2101, V. Rao Depo. at 7:18-22.

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 32, POR at 13-15







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

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

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.

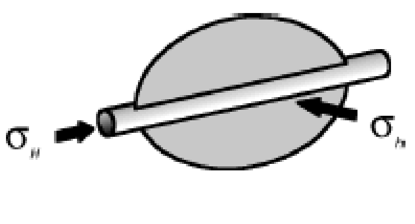


FIGURE 1: Longitudinal fracture configuration.

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[2].

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. 2039 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

[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

Q. Dr. Rao, are you familiar with the terms "complex fracture" or "fracture complexity"?

A. It can mean anything. I understand the words, but no, there's no -- no term in the literature that defines complex fractures as opposed to other fractures of complexity. You'd have to tell me what you're talking about.

Ex. 2044, V. Rao Depo. at 33:25-7.

SPE

Society of Petroleum Engineers

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

This paper was prepared for presentation at the 63rd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Houston, TX, October 2–5, 1988.

Π

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 32, POR at 21-22.

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.

References and illustrations at end of paper.

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

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; Ex. 2081, McGowen Decl. at 23; Paper 32, POR at 21-22.

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.

Ex. 2054
IPR2016-00598

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 32, POR at 21-22.

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

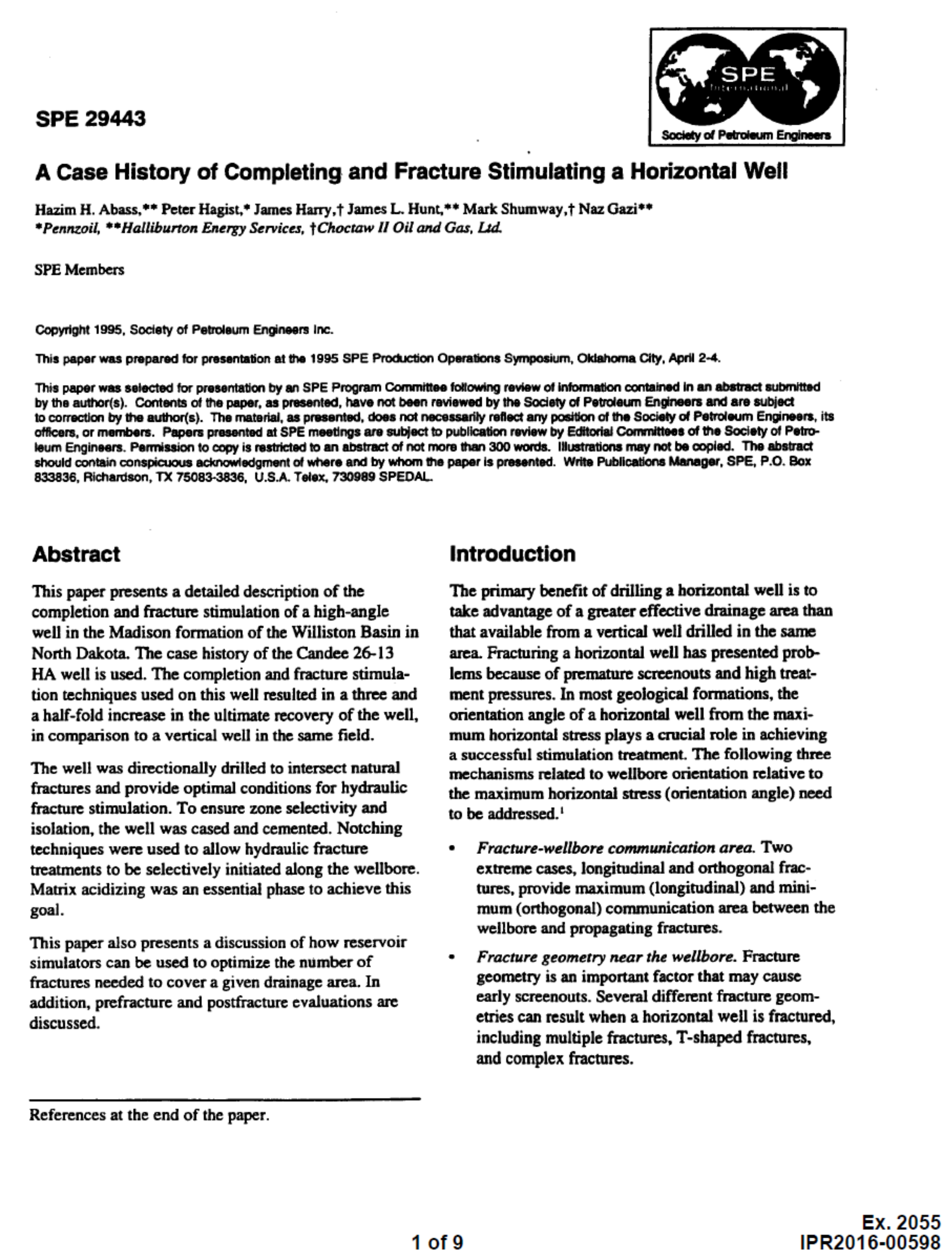
The primary benefit of drilling a horizontal well is to take advantage of a greater effective drainage area than that available from a vertical well drilled in the same area. Fracturing a horizontal well has presented problems because of premature screenouts and high treatment pressures. In most geological 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 32, POR at 21-22.


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.

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- *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.

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 32, POR at 21-22.

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.

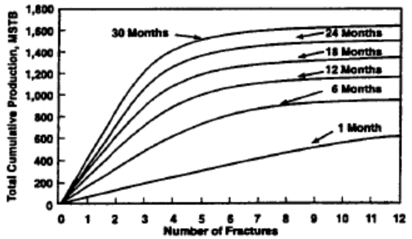

Fig. 7—Cumulative liquid production vs. the number of fractures for various times after fracturing.

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.

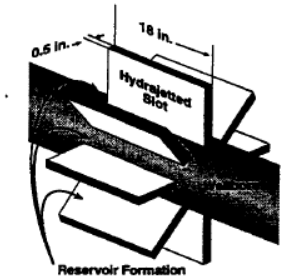

Fig. 8—Longitudinal slots created by hydrojetting.

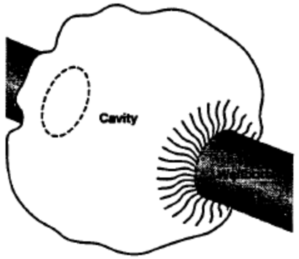

Fig. 9—Conceptual representation of what might have happened after an acid treatment.

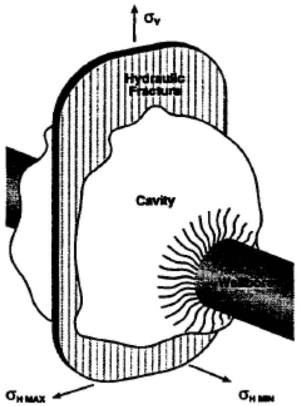

Fig. 10—Creation of the main fracture as it initiates from the cavity.

Ex. 2078
IPR2016-01506

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.
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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 32, POR at 21-22.

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.

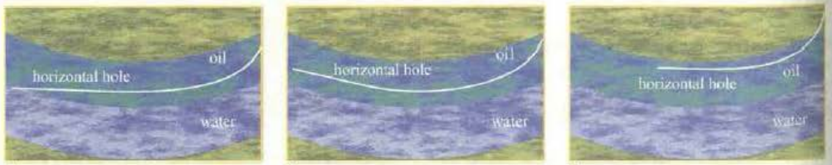
More discussion of horizontal hole completions are presented later in this chapter.

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; Paper 32, POR at 21-22.

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

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 32, POR at 23.

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 32, POR at 15-17

SPE 164009

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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

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.

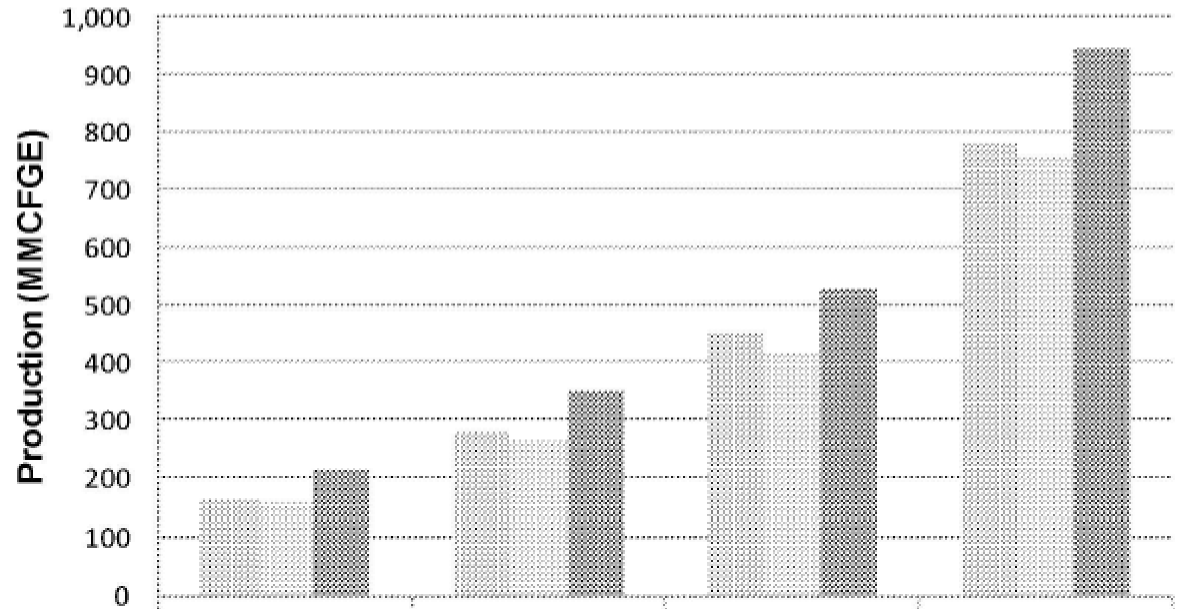
The data set for OHMS fractured wells compared to the data set for cemented fractured wells indicates that open hole wells, on average, performed better. Significantly, no failures or shut-in periods were observed for the OHMS wells. This establishes the viability, reliability and effectiveness of this 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.

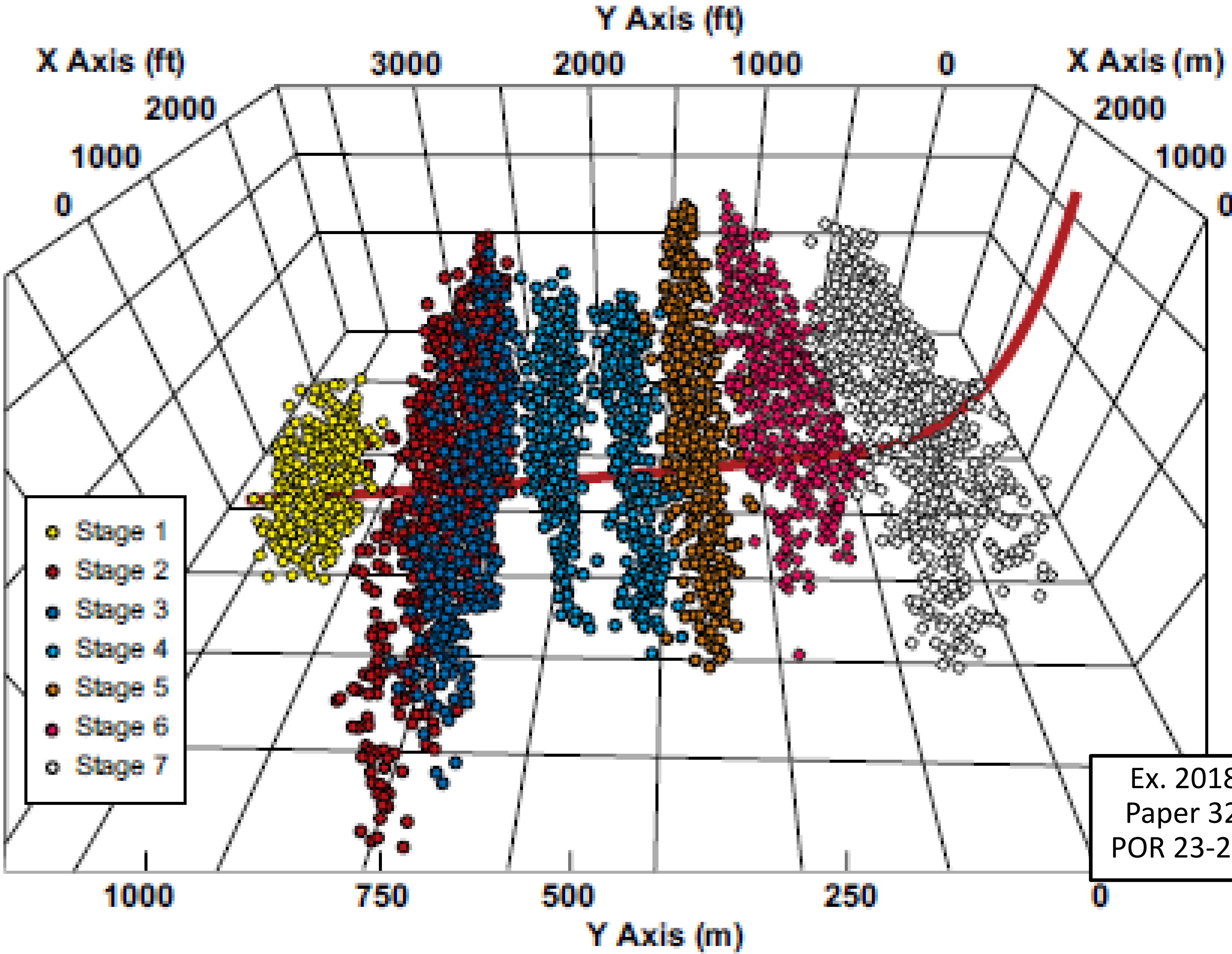
The Barnett is conformably overlain by the Pennsylvanian-age Marble Falls Limestone and unconformably overlies the Ordovician-age Viola Limestone/Ellenberger Group, which serves as a frac barrier (Figure 2) (Bowker, 2003; Pollastro et al., 2003). The core area of the Barnett is located in the Denton, 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. 2015; Paper 32, POR 23-24



Ex. 2018;
Paper 32,
POR 23-24

“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 32, 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.

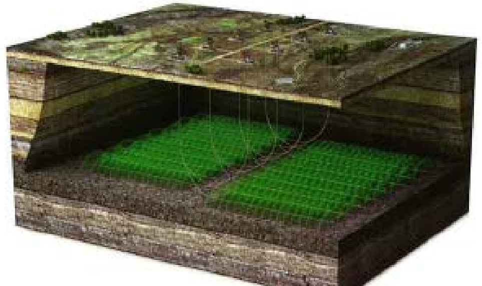
"QuickFRAC is a great technology that can meet the need for increased stage numbers in formations such as the Bakken, Horn River and the Montney as well as many others," said Themig. "QuickFRAC allows the operator to do the job of pumping 15 stages on surface while Packers Plus does the job downhole, 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 32, POR at 26-31.

ENTREPRENEUR OF THE YEAR

NATIONAL WINNER

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."

> NO. OF EMPLOYEES IN 200
> 2009: ABOUT 350
> NO. OF OPERATING
LOCATIONS IN 2000: 1
> LOCATIONS IN 2009: 25

With Packers Plus technolo
the Bakken oilfield went fro
producing 100 barrels of oil
day in 2006 to 60,000 now

FPM: Why did you
own, to start your
THEMIG: Working
vantages. Most larg
smaller company t

want you to do any
That was like puttin
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THEMIG: The whol
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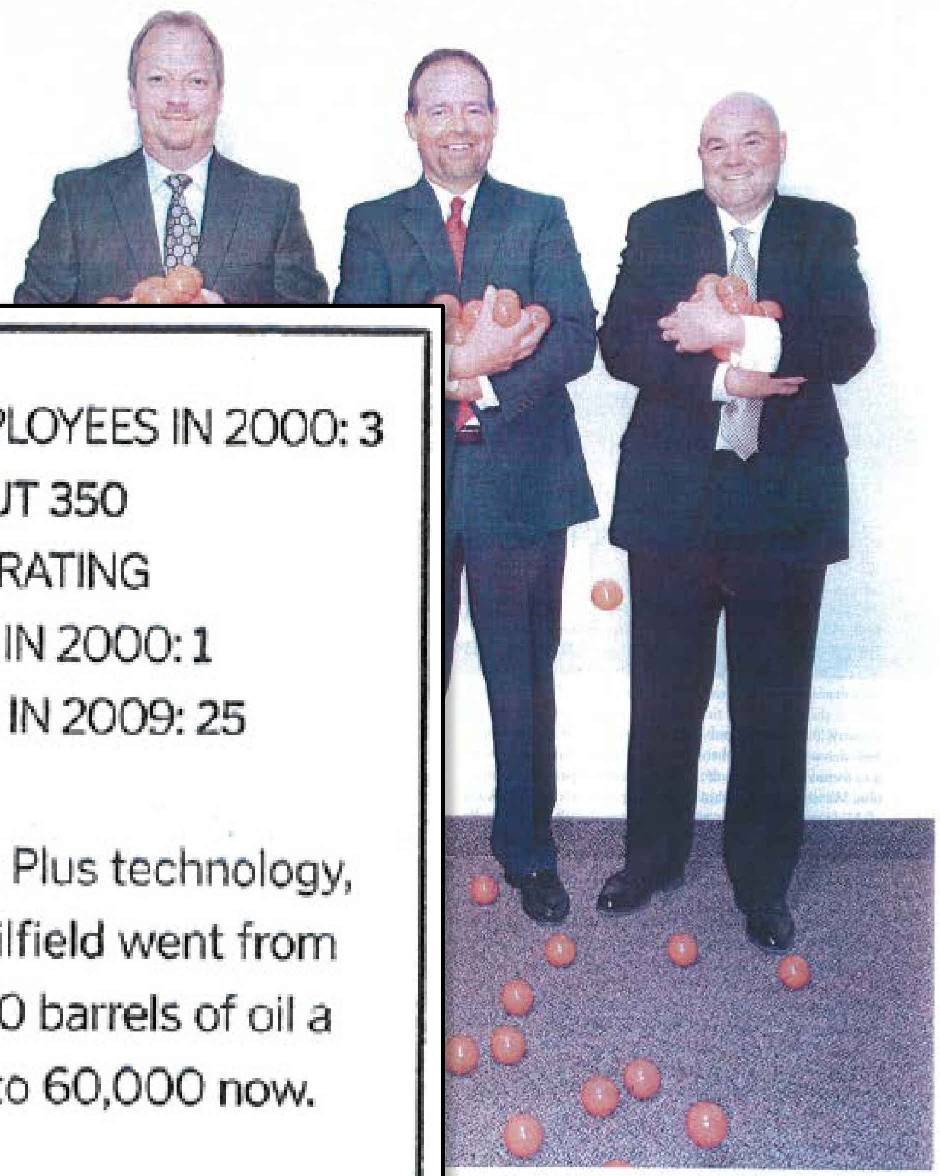
INTERVIEW BY JOANNA PA



> NO. OF EMPLOYEES IN 2000: 3
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With Packers Plus technology, the Bakken oilfield went from producing 100 barrels of oil a day in 2006 to 60,000 now.

Exhibit 2007
IPR2016-00598


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.

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Exhibit 2005
IPR2016-00598

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 to technically challenging to tap.

Ex. 2005, Exploration and Development, Alberta Oil Magazine; Paper 32, 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

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 32, POR at 26-31.

New Technology magazine

THE FIRST WORD ON OILPATCH INNOVATION

THE LATEST ISSUE

Open-Hole Or Cased And Cemented

Weighing the pros and cons of completion choices for multifrac horizontals

[Print Article: *November 2011*, by *By Pat Roche*] As the use of multiple fracture stimulations in horizontal wellbores skyrocketed in recent years, a debate emerged over the best completion method: open-hole ball drop or cased and cemented holes?

It boils down to a question of whether mechanical packers or cement provide the best means of isolating between frac stages during multiple completions in horizontal wellbores.

Murray Reynolds, a veteran completions engineer with TAQA North Ltd., looked at the advantages and disadvantages of each system in a presentation at an Infocast tight oil conference in Calgary in September.

The open-hole ball-drop system is typically associated with Calgary-based Packers Plus Energy Services Inc., though a number of competitors also run similar systems. A packer is set in the external casing, uncemented. In the case of the Packers Plus StackFRAC system, balls made of thermal-plastic material such as Teflon are dropped into the well to shift a sleeve, isolate the previous frac and open the next frac port up-hole.

Other open-hole systems use a dart instead of a ball to shift the sleeve. Others use swellable packers where an elastomer element reacts with the wellbore fluid or temperature to expand, thus creating a seal with the open-hole. Depending on conditions, it could take a week or more for these to be set up in a wellbore before a frac operation begins.

Most of the fractured horizontal well completions in western Canada use open-hole packer-based systems, which may be the cheapest option.

The Barnett shale is currently almost 100 per cent cased and cemented. Reynolds noted that early experiments with open-hole gave poorer results from the standpoint of microseismic monitoring as well as production performance.

On the other side of the debate are the advocates of fully cemented liners. These wells are typically more expensive Â¿to complete, but allow maximum control of fracture placement, providing there is good Â¿cementing in the horizontal section, which can sometimes be a challenge.

Listing the pros and cons of each system, Reynolds said the big advantage of the open-hole packer system is that it's a Â¿continuous frac process. It can be done quickly if logistics allow everything to be located on site. "If you're pumping 100,000 kilograms per fracture stage, you might not be able to do it all in one day," he said. "But generally...you can do 15 fracs in a day, or more."

Exhibit 2010
IPR2016-00598

The open-hole ball-drop system is typically associated with Calgary-based Packers Plus Energy Services Inc., though a number of competitors also run similar systems.

Ex. 2010, P. Roche, Open-Hole or Cased and Cemented, New Technology Magazine (Nov. 2011); Paper 32, POR at 26-31.

SPE 164009

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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.

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

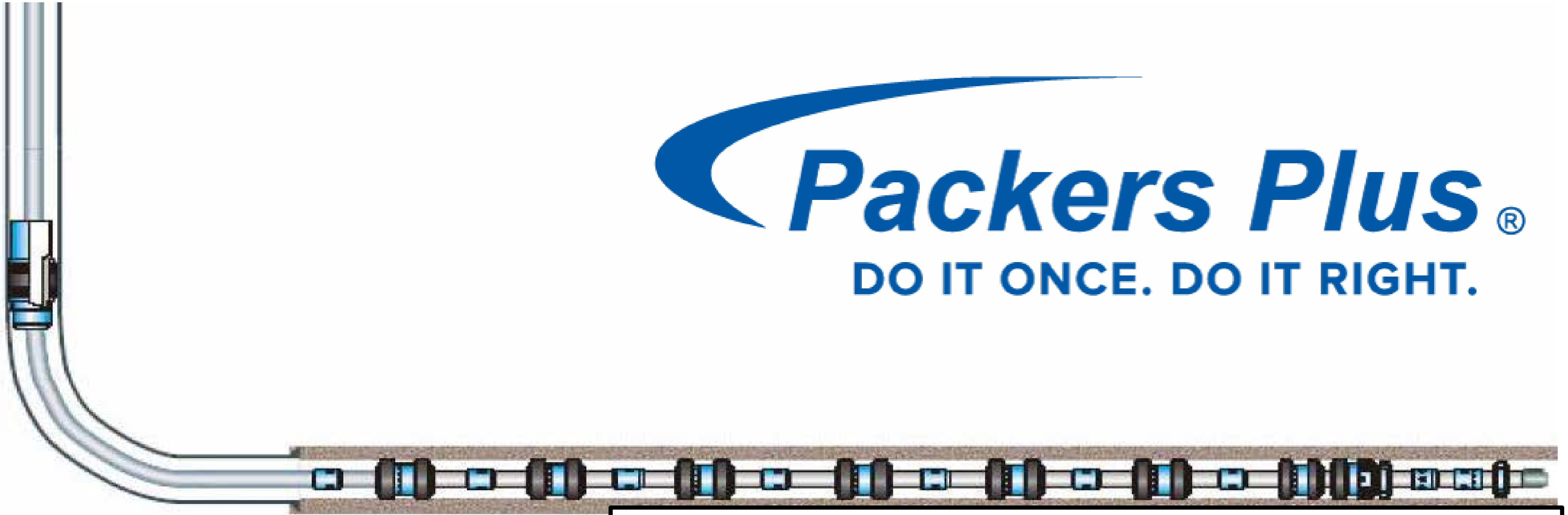
Exhibit 2001
IPR2016-00598

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 32, POR at 26-31.

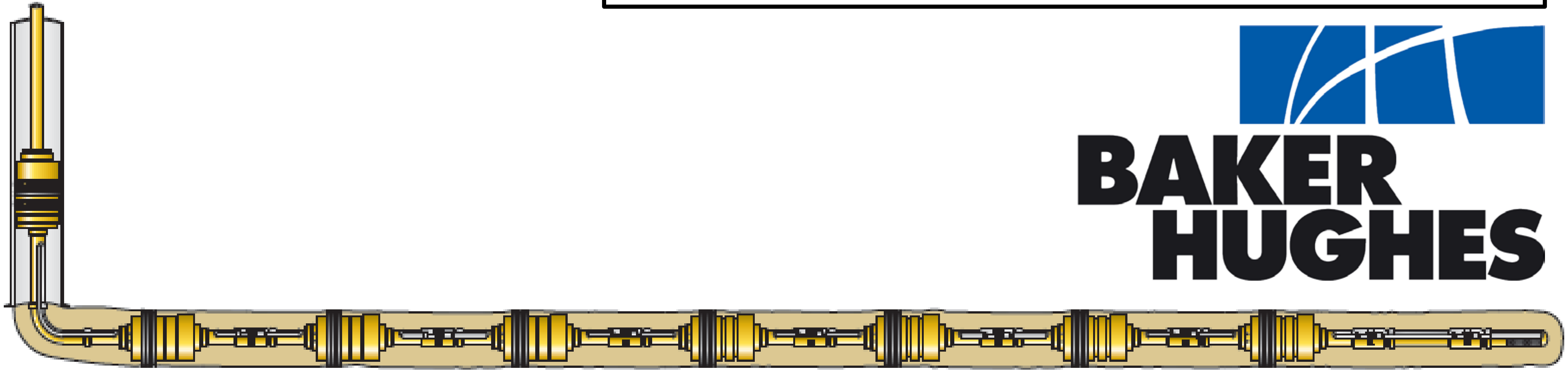
Packers Plus®

DO IT ONCE. DO IT RIGHT.



Exs. 2003; 2017; 2053; 2056; 2057; 2058 (video); 2061 (video)

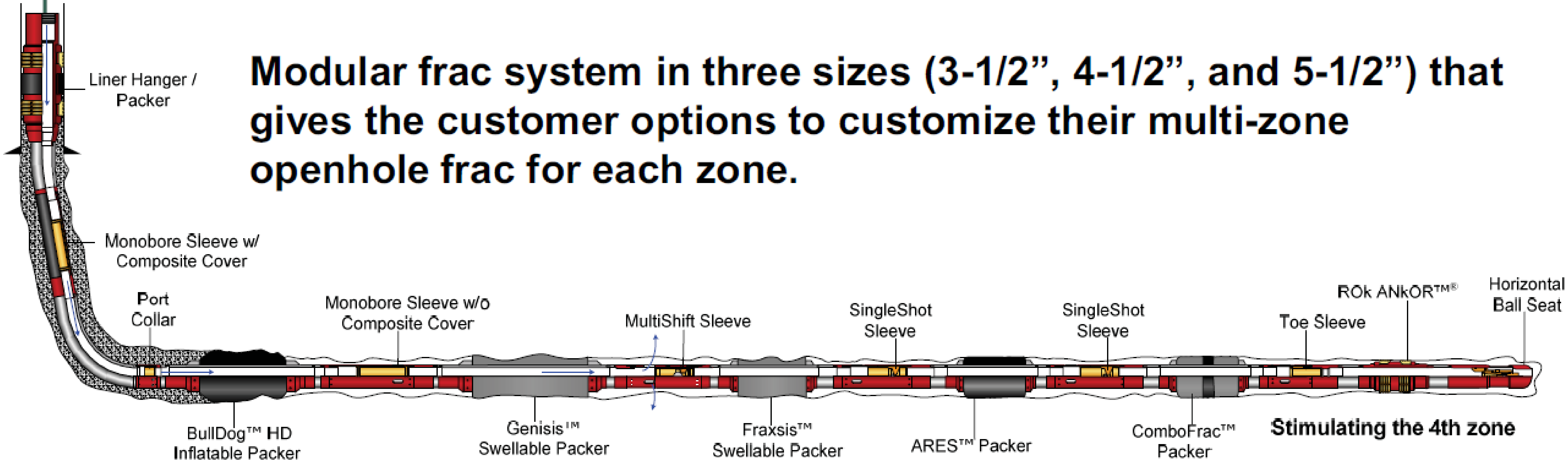
BAKER HUGHES



Exs. 2018; 2019; 2052; 2059 (video)

ZoneSelect™ Fracturing System

Modular frac system in three sizes (3-1/2", 4-1/2", and 5-1/2") that gives the customer options to customize their multi-zone openhole frac for each zone.



Ex. 2039

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

Q. Do you have any opinion as to whether StackFrac practices claim 1 of the '774 patent?

A. No, I don't have. I haven't seen what they do.

Q. Do you know that Weatherford's ZoneSelect system is an open hole ball drop system?

A. I don't, because I don't -- I don't know what it -- yeah.

Ex. 2044, V. Rao Depo. at 80:3-6, 81:4-8

IsoFrac – Generation 1

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

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 Oil Tools

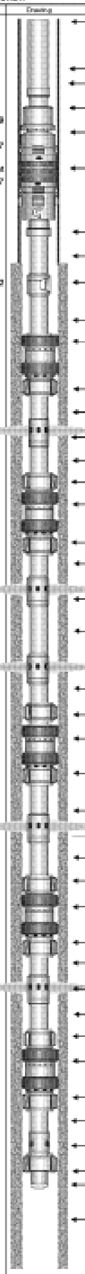
Ex. 2052 at 25-26

Packers Plus

Do it Once.
Do it Right.

Final Installation

Prepared by	Company	Date
Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-49-22W5	High Rate Acid Frac



Depth	Description	OD(mm)	ID(mm)	Length
Vertical Section	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				
Build Section 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
Horizontal Section	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
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**		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
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
4488.32	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			

Service Center	Telephone	Contact	Telephone
Red Deer	403-340-0735	Woody Randell	Bruce Bond 263-7587

pm1021 Shaw 14-21-49-22W5

Ex. 2053

Iso-Frac System

Competitor Equivalent

CONFIDENTIAL

Final Installation

Prepared by	Company	Date
Matt Rees	Petro-Canada	Aug.10/03
Shaw	14-21-49-22W5	High Rate Acid Frac

Depth	Description	OD(mm)	ID(mm)	Length
Vertical Section	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			
Build Section 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 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
Horizontal Section	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 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		44.45	0.55
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	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.			

Service Center	Telephone	Contact	Telephone
Red Deer	403-340-0735	Woody Randell	Bruce Bond 263-7587

... 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 | Drawing | Description | OD(mm) | ID(mm) | Length

Vertical Section

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
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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 0.58
(API Modified)

177.8mm x 88.9mm EUE Plus-6 mechanical retrievable dou 2.44
RH set and release and emergency shear safety release (A

Horizontal Section

88.9mm EUE High Pressure 10K sealed Tubing swivel c/w 0.31
P-110 Material
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 0.44
(API Modified) P-110 Landing Nipple to be Halliburton c
88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Colla 15.02

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

177.8mm x 88.9mm RockSeal II packer with HPHT packing element - hydraulic set shear release 146.05 69.85 1.27
Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)

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 146.05 69.85 1.27
Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)

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 50.80 0.55
2 1/4" ball for 2" Seat

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 ... set shear release 146.05 69.85 1.27
Heavy Wa...

152.40mm Open Hole

Rockseal c... 147.62 0.28

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

Vertical Section

Build Section

Horizontal Section

177.8mm Casing 47.16Kg/m L-80 set at 3995m
Picked up for tubing compression
KBD
Hanger
Pin to pin hanger cross over
4 PH-6 pups lengths-1.25, 1.71, 2.33, 2.97
114.3mm 23.10 kg/m PH-6 Hydril premium connection tu
114.30mm PH-6 Hydril 403 Box 88.90mm EUE Pin L-80
7" 3.5
177.8mm x 88.9mm PL on-off tool with LH release c/w O
(API Modified)

177.8mm x 88.9mm EUE Plus-6 mechanical retrievable d
RH set and release and emergency shear safety release

88.9mm EUE High Pressure 10K sealed Tubing swivel c/
P-110 Material
88.90mm EUE 13.84 kg/m L-80 Tubing c/w Bevelled Co
88.90mm EUE Profile Nipple Otis Original 'XN' w/ 69.85m
(API Modified) P-110 Landing Nipple to be Halliburton
88.90mm EUE 13.84 kg/m L-80 Tubing c/w Regular Col
177.8mm x 88.9mm RockSeal II packer with HPHT pack
Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)

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

407

2.75

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

2 1/2" ball for 2 1/4" Seat
88.90mm EUE 13.84 kg/m P-110 Tubing c/w Bevelled Collars 41.48

5.81

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 146.05 69.85 1.27
Heavy Wall P-110 Mandrel Material (Approximate setting pressure 15.5mpa)

5.75

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 50.80 0.55
2 1/4" ball for 2" Seat

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

4322.79

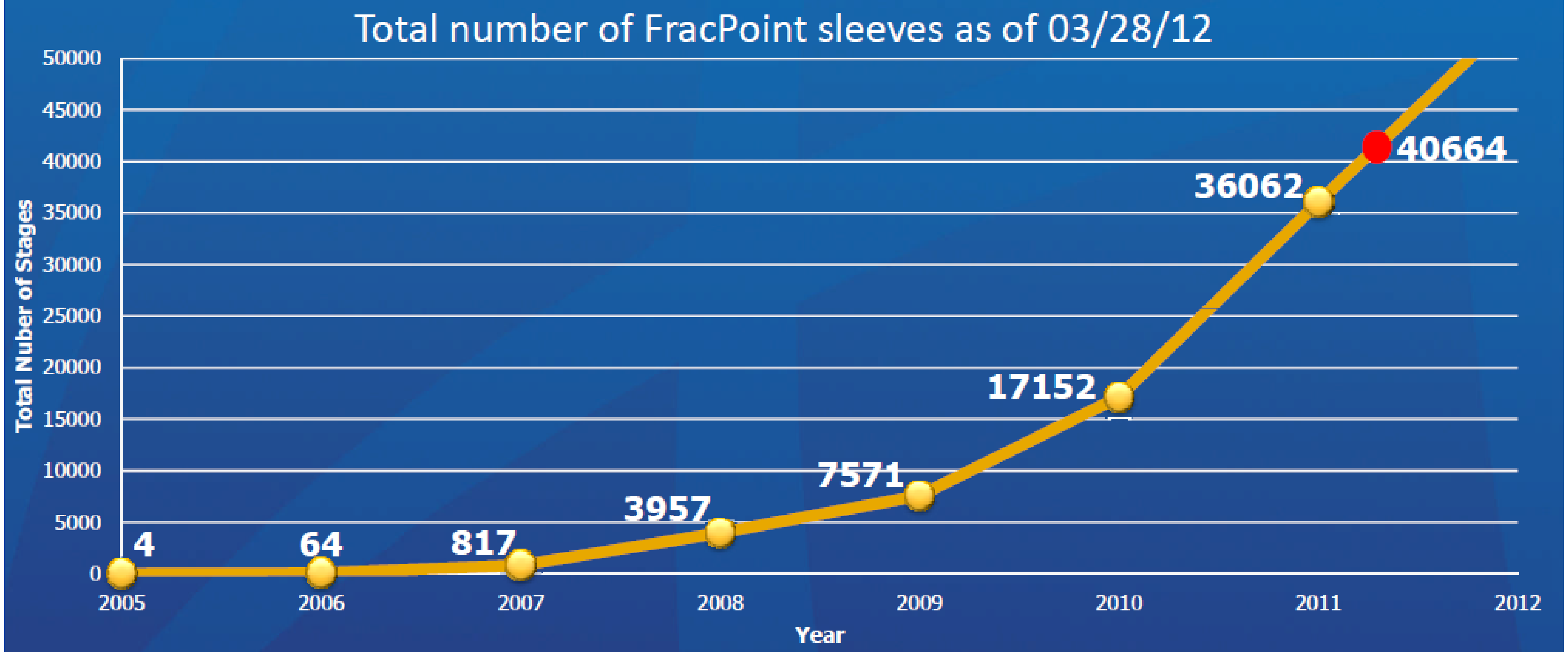
177.8mm x ... 146.05 69.85 1.27
Heavy Wall ...

152.40mm Open Hole

Rockseal ce... 147.62 0.28

Ex. 2052

FracPoint Experience in North America

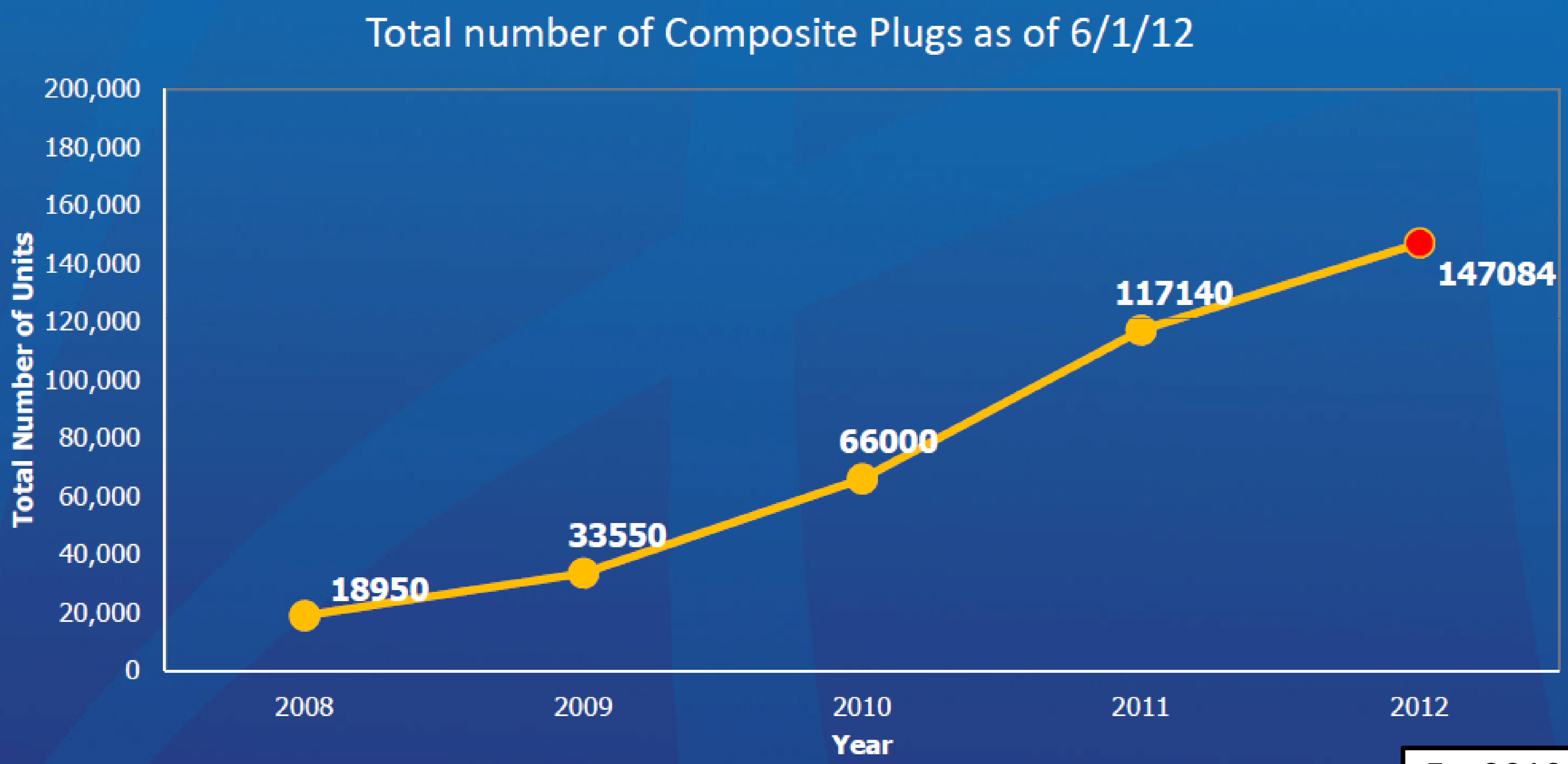


- Installed in more than 35 formations by 117 Oil & Gas Operators
- Trends – Increased number of stages per system
- >2400 Wells-38,000 Packers-40,000 Sleeves

Ex. 2019 at 6

Paper 32, POR at 38-40

Plug & Perf Experience in North America



Ex. 2019 at 5

Paper 32, POR at 38-40

Qittitut Consulting

Openhole Multistage vs Plug-n-Perf Completions

Sleeves vs Shots—The Debate Ra

by Richard G. Ghiselin, P.E.

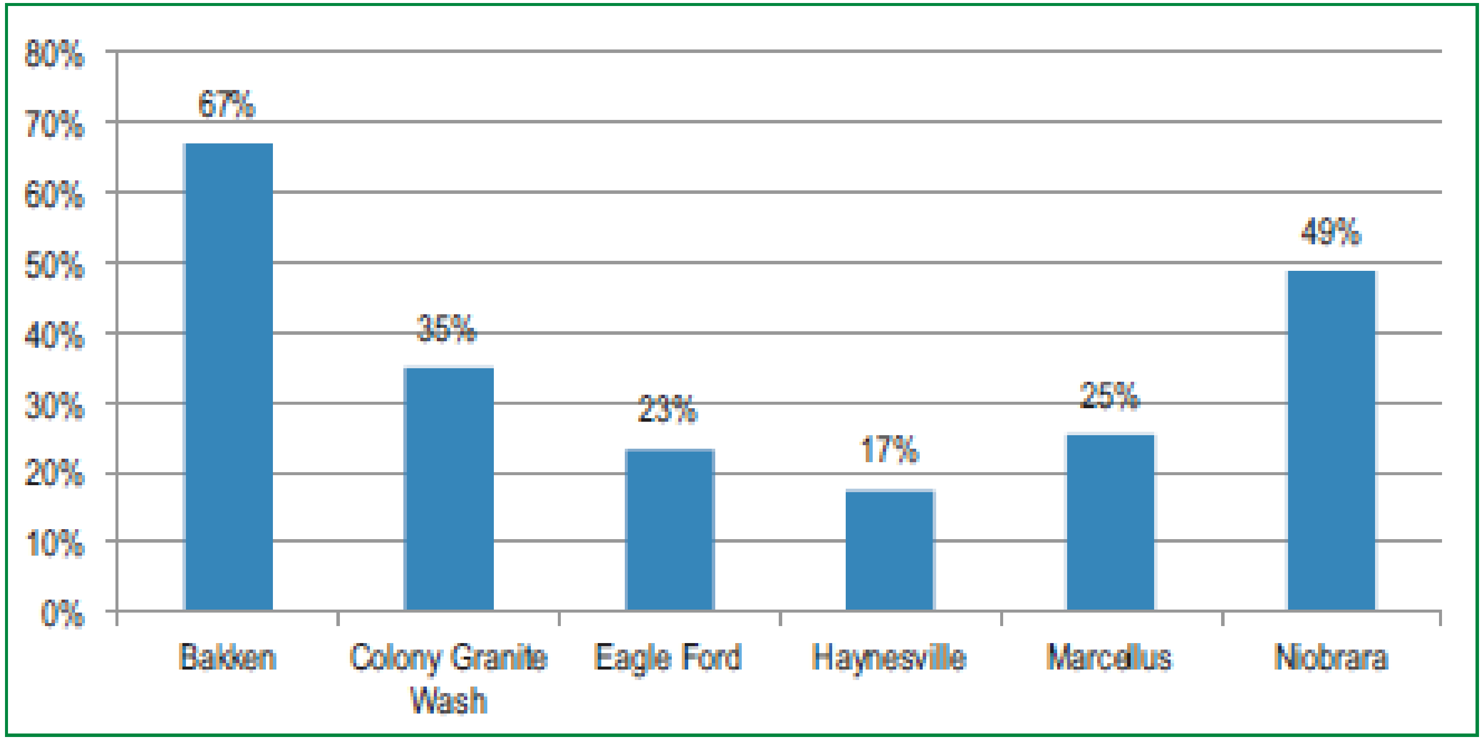


Figure 1. The OHMS technique for frac treatments is used in the Bakken play more than in other plays.

Exhibit 2011
IPR2016-00598

Ex. 2011 at 4

Paper 32, POR at 38-40

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

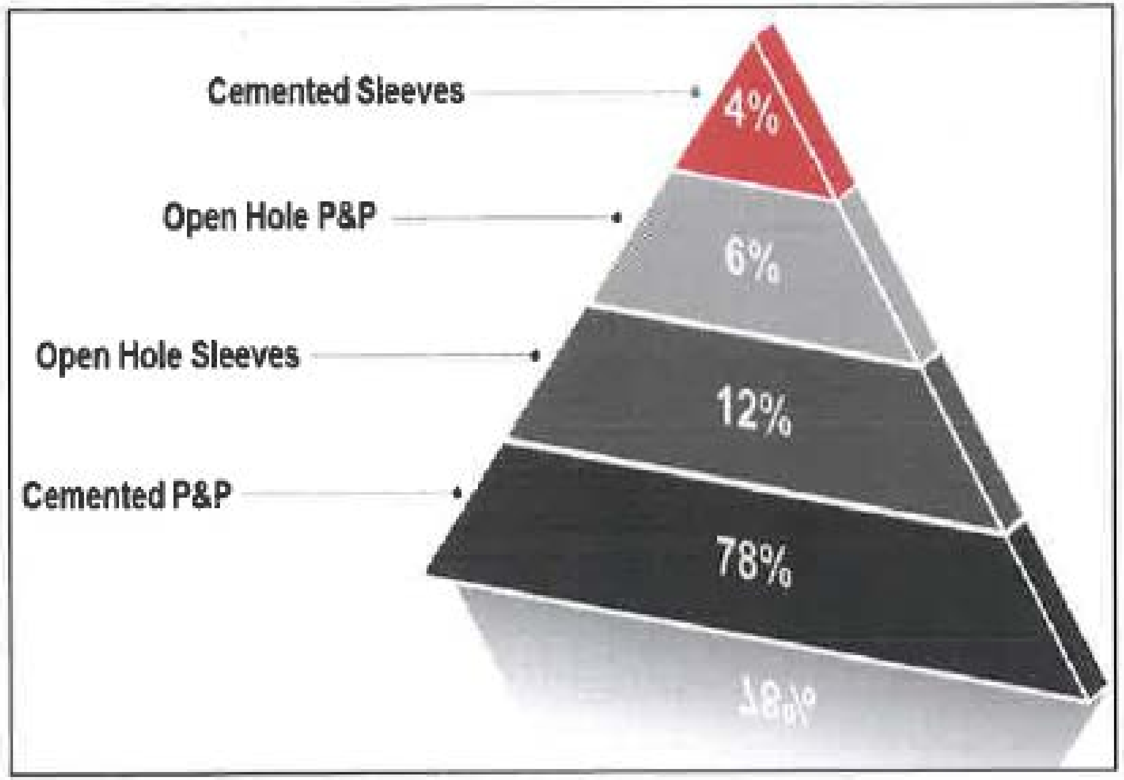


Figure 1—Percentages for different frac methods at Weatherford.

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 38-40

Packers Plus®

DO IT ONCE. DO IT RIGHT.

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

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. 2034, McGowen Decl. at 47

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)

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).

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)

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

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

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.

Ex. 1012, second provisional at 9

For ComboFrac, Fraxsis, Morphisis, Genisis, SwellCat, and Nemesis 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. 2081, McGowen Dec. at 38.

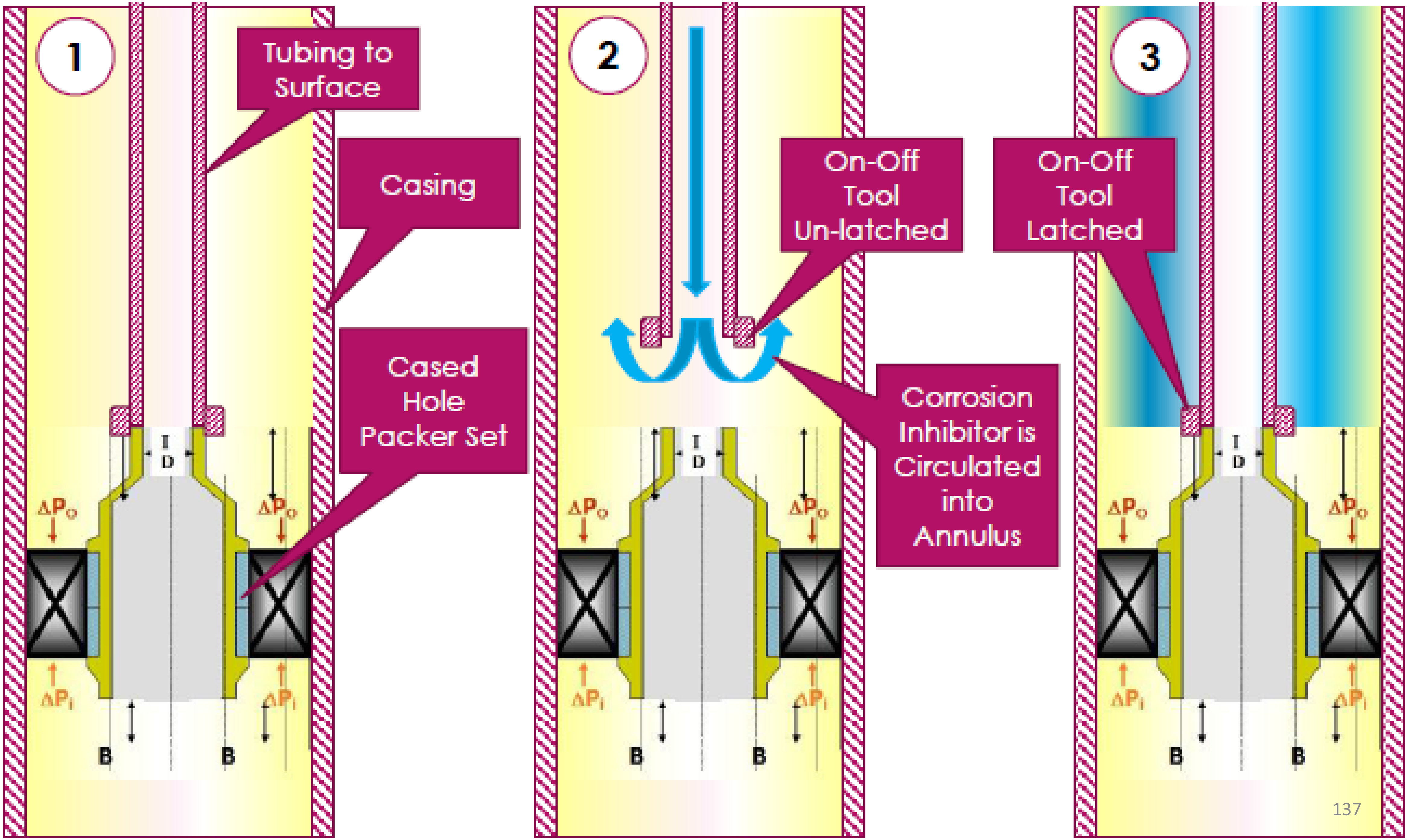
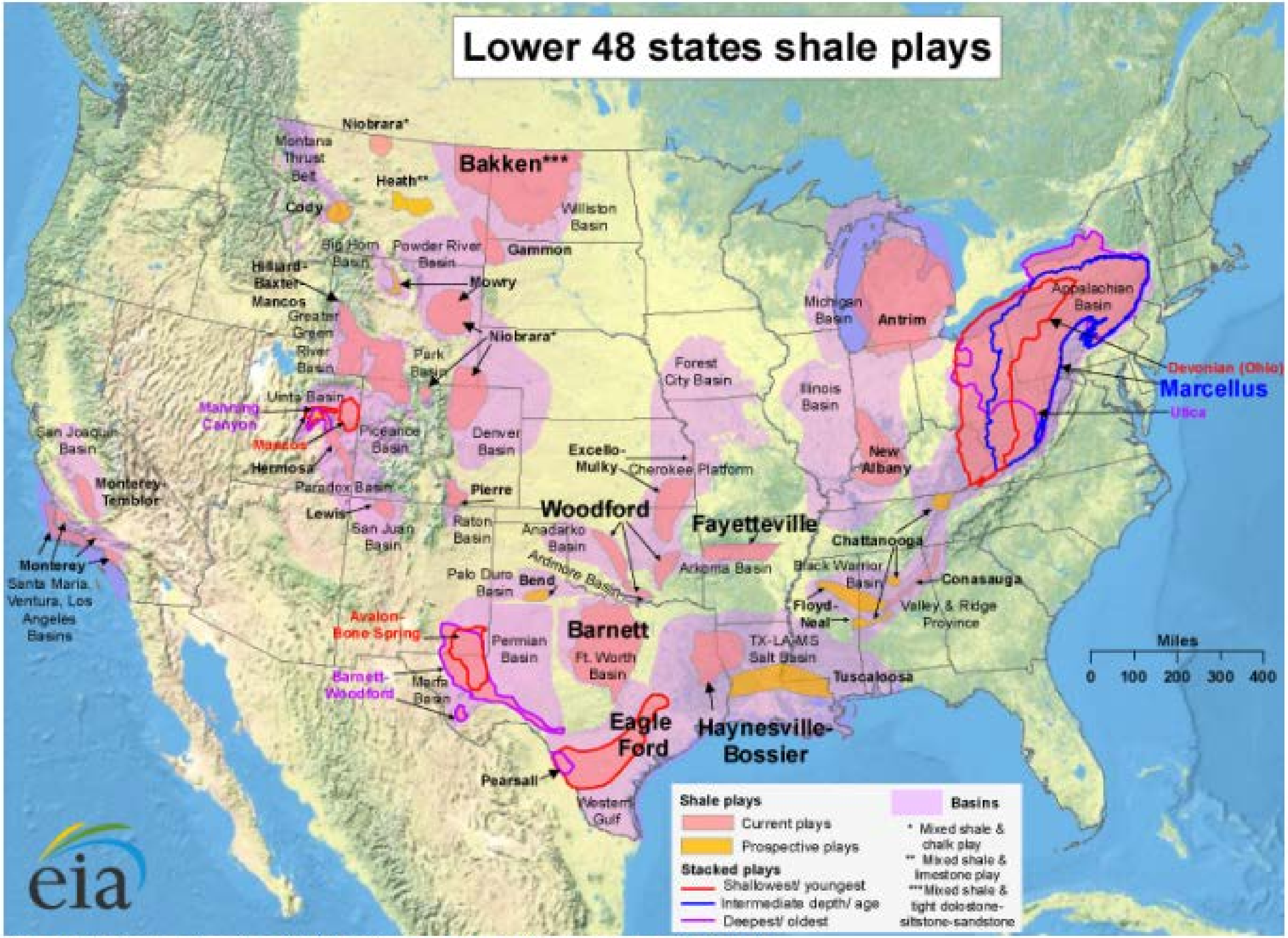

1
Tubing to Surface
Casing
Cased Hole Packer Set
2
On-Off Tool Un-latched
Corrosion Inhibitor is Circulated into Annulus
3
On-Off Tool Latched
ID
ΔP_o
ΔP_i
B

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

By */Justin T. Nemunaitis/*

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CERTIFICATION OF SERVICE

The undersigned hereby certifies that PATENT OWNER'S ORAL HEARING DEMONSTRATIVES were served via electronic mail, as previously consented to by Petitioner upon the following counsel of record:

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Date: October 31, 2017

/Hamad M. Hamad/

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