THE EVALUATION OF WATERFRAC TECHNOLOGY IN LOW-PERMEABILITY GAS SANDS IN THE EAST TEXAS BASIN

A Thesis

by

NICHOLAS RAY TSCHIRHART

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2005

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stephen A. Holditch
Committee Members,	Stuart L. Scott
	William Schneider
Head of Department,	Stephen A. Holditch

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ABSTRACT

The Evaluation of Waterfrac Technology in Low-Permeability

Gas Sands in the East Texas Basin. (August 2005)

Nicholas Ray Tschirhart, B.S., Texas A&M University

Chairman of Advisory Committee: Dr. Stephen A. Holditch

The petroleum engineering literature clearly shows that large proppant volumes and concentrations are required to effectively stimulate low-permeability gas sands. To pump large proppant concentrations, one must use a viscous fluid. However, many operators believe that low-viscosity, low-proppant concentration fracture stimulation treatments known as 'waterfracs' produce comparable stimulation results in low-permeability gas sands and are preferred because they are less expensive than gelled fracture treatments.

This study evaluates fracture stimulation technology in tight gas sands by using case histories found in the petroleum engineering literature and by using a comparison of the performance of wells stimulated with different treatment sizes in the Cotton Valley sands of the East Texas basin. This study shows that large proppant volumes and viscous fluids are necessary to optimally stimulate tight gas sand reservoirs. When large proppant volumes and viscous fluids are not successful in stimulating tight sands, it is typically because the fracture fluids have not been optimal for the reservoir conditions. This study shows that waterfracs do produce comparable results to conventional large treatments in the

Cotton Valley sands of the East Texas basin, but we believe it is because the conventional treatments have not been optimized. This is most likely because the fluids used in conventional treatments are not appropriate or have not been used appropriately for Cotton Valley conditions.

ACKNOWLEDGEMENTS

I would like to thank Matador Resources Inc., Richard Sullivan, Dave Leopold, Ken Kirby, Jim Craig, Larry Tschirhart, Jeff Asbill, John Jochen, John Spivey, Schlumberger DCS, and my advisory committee for their help and support in completing this project. I would especially like to thank Dr. Holditch for his guidance and generosity throughout my pursuit of this degree.

I thank my Lord and Savior Jesus Christ for sustaining and directing me through the completion of this thesis and the requirements for the M.S. degree.

DEDICATION

This thesis is dedicated to my father, Larry Tschirhart, who is my inspiration as I pursue becoming an engineer and a man of God. He is an example to me of wisdom, integrity, character, and what it means to be a man. I love you, Dad.

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INTRODUCTION

Tight Gas Sands – A Vital Source of Energy

In 2001 the Gas Technology Institute predicted that natural gas will account for 28% of the United States' total energy consumption by the year 2015.[1] According to the EIA 2004 International Energy Outlook, 'Natural gas is the fastest growing primary energy source…Consumption of natural gas is projected to increase by nearly 70 percent between 2001 and 2025...'[2] Natural gas will continue to play an important role in providing the energy the United States and the rest of the world needs. Much of the natural gas the United States produces and consumes comes from unconventional gas reservoirs. Unconventional gas reservoirs are natural gas reservoirs that require advanced stimulation technology to make their development economic. The United States produced approximately 19.8 Tcf of natural gas in 2001.[3] Unconventional gas contributed to 27% of this total production.[3] In 20 years, the National Petroleum Council expects the yearly unconventional gas production to increase to about 10 Tcf.[4] This is almost twice the unconventional gas produced during 2001. Low-permeability sandstone, reservoirs more commonly called tight gas sands, account for the majority of unconventional gas production – as much as 60%.[3] The basins of the lower 48 states alone are believed to contain 441 Tcf of technically recoverable unconventional natural gas.[3]

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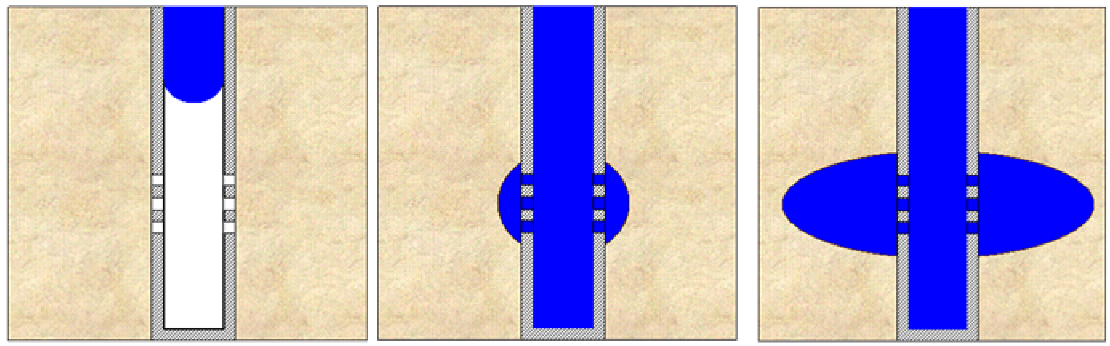
This thesis follows the form and style of the *Journal of Petroleum Technology.*

This estimate is expected to increase as new plays are identified and technology is improved. Tight gas sands will continue to be a vital source of energy for the United States as well as to the rest of the world as conventional gas reservoirs around the world begin to deplete.

Hydraulic Fracture Stimulation

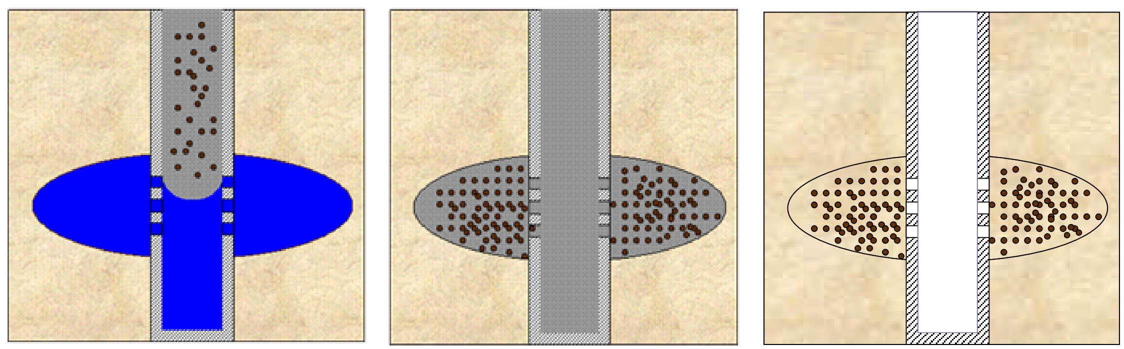
Hydraulic fracture stimulation makes development of tight gas sands and other unconventional gas reservoirs possible. The basic process of hydraulic fracture stimulation shown in **Fig. 1** consists of propagating a fracture in the reservoir and holding this fracture open with propping agents, commonly called proppants. Fluid is first pumped at a high pressure down the well. A fracture is initiated and propagated in the reservoir by the hydraulic pressure of the fluid. Upon creating the fracture, a slurry consisting of proppants and a transport fluid is pumped into the fracture. Proppants are usually a high strength small grained substance such as sand. After the proppants are pumped into the fracture, the transport fluid leaks off into the reservoir or is allowed to flow back into the wellbore, allowing the fracture to close upon the proppants. The desired result is a conductive fracture filled with proppant extending deeply into the reservoir.



a. Fluid is pumped down well.

b. Hydraulic pressure of fluid initiates a fracture in the reservoir.

c. Fracture begins propagating into reservoir.



d. Proppant is transported with viscous fluid into fracture.

e. Viscous fluid uniformly transports fluid deeply into the fracture.

f. Viscous fluid breaks and is allowed to flow back out of well. The formation closes upon proppants resulting in a long conductive fracture.

Fig. 1 – Basic Hydraulic Fracturing Process

Stimulating Tight Sands

Hydraulic fracture stimulation dramatically improves the performance of a well because it effectively transforms the path fluids must take to enter the wellbore. **Fig. 2a** shows an example of what the flow path of natural gas may look like from the reservoir to the wellbore prior to stimulation. As can be seen all of the gas must converge radially on a very small area called the wellbore. For a radial flow pattern, most of the pressure drop in the reservoir occurs near the wellbore.

Fig. 2b shows what the flow path of natural gas from the reservoir to the wellbore may look like after a successful fracture stimulation treatment. Natural gas enters into the fracture from all points along the fracture in a linear fashion. The highly conductive fracture rapidly transports the gas to the wellbore. In low-permeability reservoirs such as tight gas sands, the fracture can contact more gas in the reservoir and substantially improve the flow rates and productivity of the well. Conventional wisdom in designing hydraulic fracture treatments for tight gas sands would suggest that successful stimulation of tight gas sands requires creating a long, conductive fracture filled with proppant opposite the pay zone interval. This is accomplished by pumping large volumes of proppant at high concentrations into the fracture using viscous transport fluids to uniformly distribute proppant deeply into the fracture.

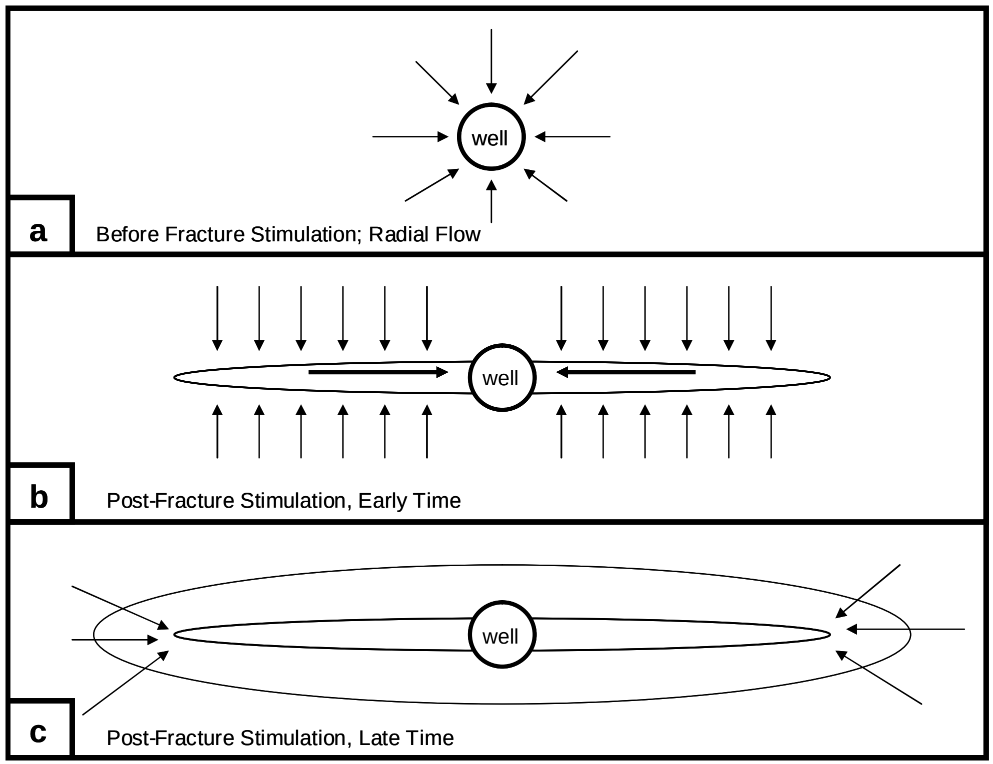


Fig. 2 – Comparison of Flow Streamlines for Fractured and Non-Fractured Wells

Waterfracs Emerge as Stimulation Technique in the East Texas Basin

A few operators began using waterfracs to stimulate tight sands in the East Texas basin during the late 1990s because of the success they had with this technology in the Austin Chalk formation. A waterfrac is fracture treatment using low viscosity fluid carrying proppant at low concentrations. The fracturing fluid is often called slick water as only friction reducer is added to the fracturing fluid to reduce the required hydraulic horsepower needed to pump the treatment. High injection rates, anywhere from 40 to 100 bbl/min, are used to minimize pumping time, minimize leakoff time, and maximize proppant transport. The first part of a fracture treatment is the pad, or the fluid pumped without any proppant. Pad volumes are typically about 50% of the total fluid volume pumped. Depending on the job size, several low volume, low-proppant concentration stages are pumped following the pad. The proppant stages are alternated with proppant-free, slick water stages commonly called sweeps. Sweeps function primarily to push away the proppant that is settling in the fracture near the wellbore to keep the perforations from plugging. The proppant concentrations of the proppant stages are gradually increased as the treatment progresses. Proppant concentrations typically around 0.25 ppg (pounds per gallon) gradually increase to around 2.0-3.0 ppg during the final stages of the treatment. An example of a pump schedule for a typical East Texas waterfrac treatment is shown in **Table 1.**

Table 1 – Waterfrac Pump Schedule

Stage	Pump Rate (bbl/min)	Fluid Volume (gal)	Proppant Conc. (lb/gal)	Stage Description
1	60	50000	0.0	Pad
2	60	5000	0.3	Proppant Ladden
3	60	4000	0.0	Sweep
4	60	5000	0.3	Proppant Ladden
5	60	4000	0.0	Sweep
6	60	5000	0.3	Proppant Ladden
7	60	4000	0.0	Sweep
8	60	5000	0.5	Proppant Ladden
9	60	4000	0.0	Sweep
10	60	5000	0.5	Proppant Ladden
11	60	4000	0.0	Sweep
12	60	5000	0.8	Proppant Ladden
13	60	4000	0.0	Sweep
14	60	5000	0.8	Proppant Ladden
15	60	4000	0.0	Sweep
16	60	5000	0.8	Proppant Ladden
17	60	4000	0.0	Sweep
18	60	5000	1.0	Proppant Ladden
19	60	4000	0.0	Sweep
20	60	5000	1.0	Proppant Ladden
21	60	4000	0.0	Sweep
22	60	5000	1.0	Proppant Ladden
23	60	4000	0.0	Sweep
24	60	5000	1.0	Proppant Ladden
25	60	4000	0.0	Sweep
26	60	5000	1.3	Proppant Ladden
27	60	4000	0.0	Sweep
28	60	5000	1.3	Proppant Ladden
29	60	4000	0.0	Sweep
30	60	5000	1.3	Proppant Ladden

Stage	Pump Rate (bbl/min)	Fluid Volume (gal)	Proppant Conc. (lb/gal)	Stage Description
31	60	4000	0.0	Sweep
32	60	5000	1.5	Proppant Ladden
33	60	6000	0.0	Sweep
34	60	5000	1.5	Proppant Ladden
35	60	4000	0.0	Sweep
36	60	5000	1.5	Proppant Ladden
37	60	4000	0.0	Sweep
38	60	5000	1.8	Proppant Ladden
39	60	6000	0.0	Sweep
40	60	5000	1.8	Proppant Ladden
41	60	4000	0.0	Sweep
42	60	5000	1.8	Proppant Ladden
43	60	4000	0.0	Sweep
44	60	5000	2.0	Proppant Ladden
45	60	6000	0.0	Sweep
46	60	5000	2.0	Proppant Ladden
47	60	4000	0.0	Sweep
48	60	5000	2.0	Proppant Ladden
49	60	4000	0.0	Sweep
50	60	5000	2.3	Proppant Ladden
51	60	6000	0.0	Sweep
52	60	5000	2.3	Proppant Ladden
53	60	4000	0.0	Sweep
54	60	5000	2.3	Proppant Ladden
55	60	4000	0.0	Sweep
56	60	5000	2.5	Proppant Ladden
57	60	6000	0.0	Sweep
58	60	5000	2.5	Proppant Ladden
59	60	4000	0.0	Sweep
60	60	5000	2.5	Proppant Ladden

In conventional gel fracture treatments, viscous fluids are used to suspend the proppants so they can be transported deeply into the fracture. In water fracture treatments, the proppants settle to the bottom of the fracture, and a proppant bank is built from the bottom of the fracture. Waterfracs will work if a proppant bank is built high enough to connect the proppant bank with the perforations. A number of papers have been written comparing waterfracs with gel fracture treatments in the East Texas basin.[5-7] Following these publications, many operators began using waterfrac treatments to stimulate tight sands in the East Texas basin because the waterfrac treatments cost much less than the conventional treatments and the resulting gas flow rates of the waterfracs appeared to be comparable to the gel fracture treatments. Use of the waterfrac treatments in this region still prevails today.

Evaluation of Stimulation Technology in Tight Sands

Basic reservoir engineering principles suggest that when tight gas sand reservoirs are stimulated, the following two concepts should be true:

1. Gas recovery and deliverability will be a function of propped fracture length and fracture conductivity in the reservoir interval.

2. Viscous fracture fluids transporting high proppant concentrations should provide more stimulation than waterfrac treatments carrying less proppant

provided the treatment stays within zone, the fracture face is not severely damaged, and the fracture fluid breaks and cleans up properly.

This study tests the above concepts and evaluates waterfrac technology using case history examples from the petroleum engineering literature and an analysis of the performance of wells stimulated with different treatments in the Cotton Valley sands of the East Texas basin. Well performance, analytical simulation, and basic statistical analysis is used to compare the success of large proppant volume, high viscosity treatments and low proppant volume, low viscosity treatments in the Cotton Valley formation of Carthage field.

LITERATURE REVIEW

Why Waterfracs May Work

Waterfrac treatments have been successful in reservoirs other than tight sands. Explanations for success vary depending on the geology of the reservoir. For example, waterfrac success in the Austin Chalk and the Barnett Shale(a fractured shale reservoir) has been attributed to the waterfrac's ability to open existing natural fractures. Also the water will imbibe into the matrix blocks and expel the oil or gas into the natural fractures. Fracture growth in reservoirs like the Austin Chalk or the Barnett Shale can be very different from the conventional idea that fracture stimulation predominately creates two single fracture wings extending from the well. Instead, large fracture networks are created increasing the surface area of the fractures.[8] The concept of multiple fractures is supported by microseismic and tiltmeter fracture mapping experiments.[8] **Fig 3a** and **Fig. 3b** show an example of a simple conventional fracture geometry as opposed to a complex fracture network as may be expected from stimulating the Barnett Shale.

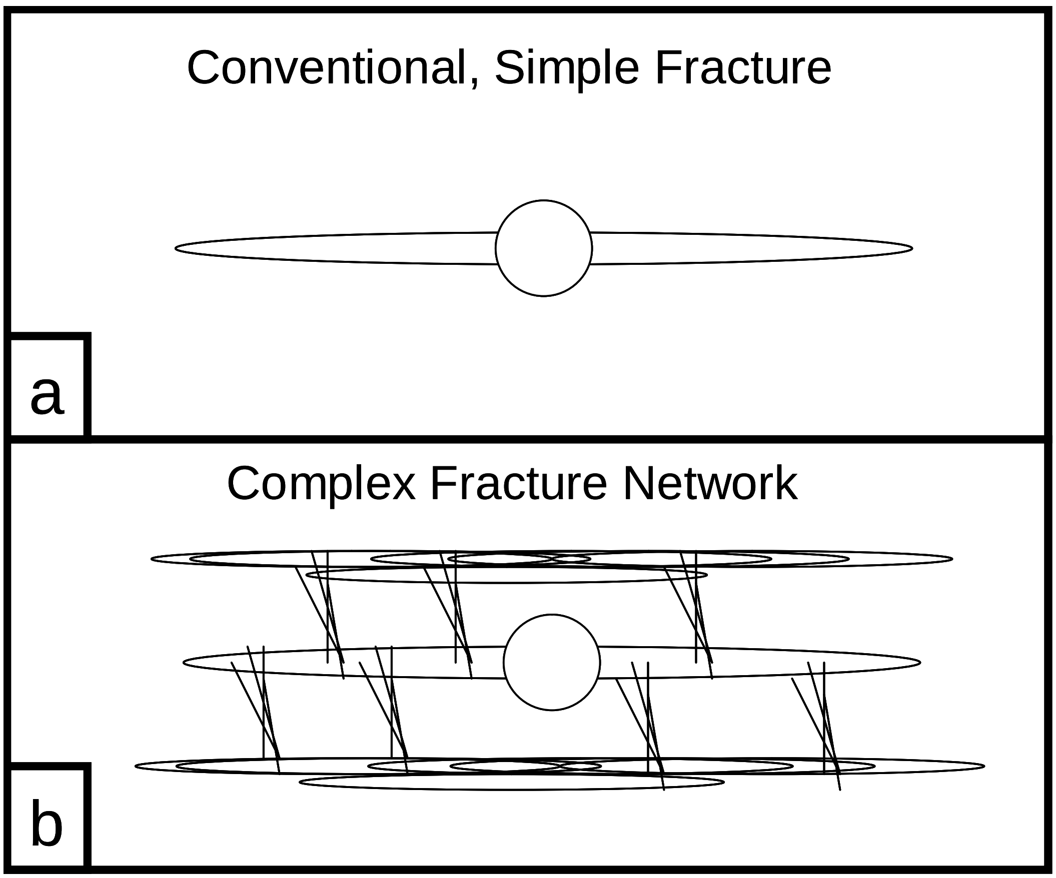


Fig. 3 – Conventional and Complex Fracture Growth (After Fisher *et al.*[8])

Capillary imbibition is considered the primary phenomenon that makes waterfracs successful in reservoirs like the Austin Chalk. Oil in the preferentially water-wet Austin Chalk is displaced by the waterfrac as water imbibes into formation.[9] In many cases, little to no sand is needed to stimulate the Austin Chalk. Though waterfrac success is reasonably well understood in reservoirs like the Barnett Shale and the Austin Chalk, there is no clear understanding why waterfracs have been successful in tight sands like the Cotton Valley sands of the East Texas basin. Two major theories exist as to why waterfracs may be successful in tight sands. The first theory suggests that the waterfrac treatments create shear displacements in the rock. As shown in **Fig. 4**, Asperities and misalignment of the rock faces upon closure of the fracture create tiny highly conductive channels.[5]

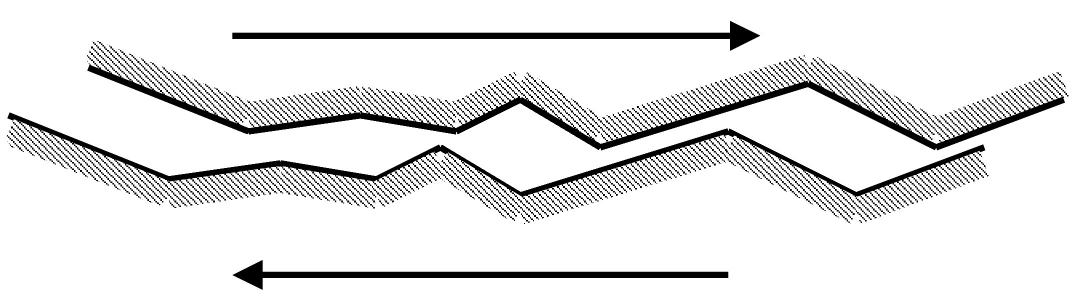


Fig. 4 – Fracture Face Misalignment

The second theory proposes that the viscous cross-linked, polymer fluids that are used in conventional treatments may leave behind residue that damages the fracture conductivity or the formation face when the treatments are not executed or designed properly. Waterfracs result in shorter fractures yet leave no fracture residue resulting in higher fracture conductivity. Effectively, both treatments are less than optimum and wells stimulated with the treatments perform comparably.[5]

Shear Failure, Misalignment, and Asperities

A few studies have investigated fracture growth in tight sands as related to shear failure and fracture face misalignment. Mayerhofer *et al.*[10] used microseismic and tiltmeter fracture mapping to evaluate fracture growth of a waterfrac treatment and a conventional treatment in the East Texas Cotton Valley. Mayerhofer *et al.*[10] predicted from microseismic results that waterfrac treatments may cause the formation to fail primarily in shear mode while the viscous, high proppant volume treatments cause the formation to fail in a manner more closely resembling volumetric failure as described by classical hydraulic fracturing theory.

Narayan, Rahman, and Jing[11] used a fracture model based solely on shear failure theory to simulate microseismic events that may occur in tight sand reservoirs using inputs from the GRI/DOE M site project. Good agreement was found between the actual microseismic events recorded at the GRI/DOE M site project and the simulated microseismic events.

Fredd *et al*.[12] investigated asperity dominated fracture conductivity and how proppants influenced fracture conductivity using cores from the Cotton Valley sands. Fredd *et al*.[12] found that asperity dominated conductivity may vary significantly with changes in asperity size and formation mechanical properties making asperity dominated conductivity hard to predict and difficult to engineer in the formation. It was concluded that the use of conventional proppant volumes was necessary to insure predictable adequate fracture conductivity.

Fracture Damage Due to Unbroken Gel and Fracture Fluid Residue

Influence of fracture damage due to unbroken gel and fracture fluid residue on well performance has been extensively documented in the petroleum literature. For example, Voneiff, Robinson, and Holditch[13] showed by simulation that unbroken gel can significantly reduce reserves and initial deliverability. Pope *et al*.[14] showed by quantitative evaluation of polymer returns during flowback that well performance is influenced by fracture fluid clean-up. It is well established that damage due to unbroken gel and fracture fluid residue can and will happen if fluids are not optimal for reservoir conditions.

Previous Comparisons of Waterfrac and Conventional Stimulation

Several studies have been published in the petroleum engineering literature comparing the effectiveness of waterfracs and conventional high viscosity, large proppant volume treatments in tight sands. Early comparisons of waterfracs and conventional hydraulic fracturing were made on the basis of post stimulation production. Mayerhofer *et al.*[5] compared wells stimulated with waterfracs and conventionally stimulated offsets on the basis of production over time. All of the wells in this study were completed in the Cotton Valley sands of East Texas. The study showed that wells stimulated with waterfrac treatments performed as good as, or better than conventionally stimulated offset wells. Mayerhofer *et al*.[5] proposed the prevailing theories for waterfrac success in tight sands as described previously.

Following the first publication by Mayerhofer *et al*[5], Mayerhofer and Meehan[6] compared a much larger sample of wells stimulated with both types of treatments in the Cotton Valley on the basis of 6-month cumulative gas production. Mayerhofer and Meehan[6] showed that overall wells stimulated with waterfracs performed as well as, or better than conventionally stimulated wells. This study will be revisited in more detail in Case History IV, discussed later in this thesis.

Other publications argued that early comparisons of waterfracs and conventional hydraulic fracture treatments do not account for the influences that reservoir quality or pressure drawdown may have on well performance. Poe *et al*.[15] used history matching techniques to compare values for conventionally gel-fractured with a sample of water fractured wells located in various fields in East and South Texas. Poe *et al*.[15] concluded that viscous fluids and high proppant volumes were more effective in stimulating tight sands on the basis of comparing fracture lengths and fracture conductivities.

England, Poe, and Conger[16] extended this work by comparing wells stimulated with waterfracs and conventional treatments performed specifically in the East Texas Cotton Valley sands using the same methods as Poe *et al*.[15] This study showed that conventionally fractured wells resulted on average in larger drainage areas, longer fracture lengths, and higher fracture conductivities than wells stimulated with waterfracs. This study will be revisited in more detail in Case History IV.

Recently, Rushing and Sullivan[17] used a combination of short-term pressure build-up analysis and long term production analysis to history match wells stimulated with waterfracs and wells stimulated with 'hybrid' fracture treatments where waterfrac technology is used as the pad fluid and viscous cross-linked fluids are used to transport proppant into the fracture. Rushing and Sullivan[17] found that wells stimulated with viscous cross-linked fluids resulted in longer fracture lengths and higher fracture conductivities than waterfracs. This study is revisited in more detail in Case History III.

TIGHT SAND STIMULATION CASE HISTORIES

The following case histories are used to investigate the results of stimulating tight sands with different treatment sizes. Identifying treatment sizes with words like "large" or "small" can be relative within a particular study. For adequate comparison between the studies and case histories treatment sizes will be grouped and referred to in the figures throughout this section as identified below in **Table 2.**

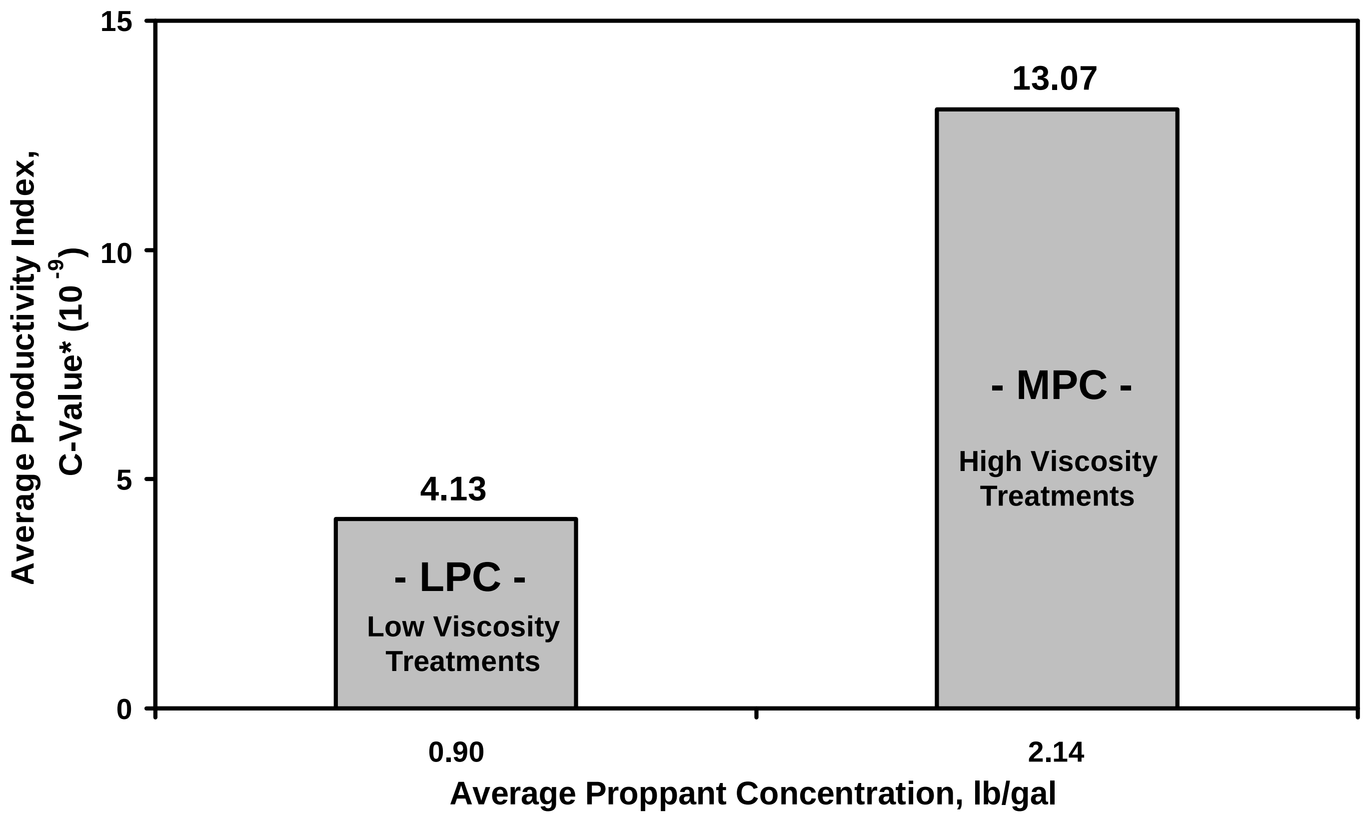
Table 2 – Treatment Size Designations

Treatment Size	Maximum Concentration Pumped During Treatment
Ultra-low Proppant Concentration (ULPC)	**< 1 ppg**
Low Proppant Concentration (LPC)	**1-2 ppg**
Medium Proppant Concentration (MPC)	**2-6 ppg**
High Proppant Concentration (HPC)	**10-12 ppg**

Case History I – Vicksburg Sand

Holditch and Ely[19] compared the long-term productivity index for wells stimulated with low viscosity fluids and low proppant volumes and for wells stimulated with high viscosity fluids and high proppant volumes. All of the wells were completed in the tight Vicksburg sand of South Texas occurring at depths between 10,500 and 12,500 ft. Bottomhole temperature in these sands is about 300°F. The wells were grouped based on similar values for permeability-thickness product, kh and porosity-thickness product, Φh. Wells were compared on the basis of their productivity index immediately after fracturing, 6 months after fracturing and 2 years after fracturing**.**

During the first few month after the treatment, both types of treatments (LPC & MPC) performed comparably. Over time, however, a significant difference in performance was observed. As shown in **Fig. 5**, wells stimulated with higher viscosity fluids and higher proppant volumes (MPC) sustained much higher productivity indices on average than wells stimulated with low viscosity fluids and low proppant volumes. (LPC) Holditch and Ely's[19] results are summarized in **Table 3**. This is a clear example where the long-term benefit of effectively placing higher proppant volumes in the fracture is shown. In this case history, the bottomhole temperature of the reservoir was around 290-300°F. At this temperature, gel fluids will break and clean-up so that the polymer damage in the fracture is usually not expected. As such, in deep, hot, tight gas reservoirs, it is clear that putting more proppant in the fracture can be achieved with viscous cross-linked fluids.



** Determined using production data 2 years after the fracture treatment for well groupings with similar values of kh and Φh*

Fig. 5 – Long-term Productivity and Treatment Sizes in the Vicksburg Sand (Data from Holditch and Ely[19])

Table 3 – Vicksburg Case History Data (From Holditch and Ely[19])

Treatment Size	Well	Viscosity	k (md)	Fluid (gal)	Proppant (lb)	Productivity Index (C-Value X 10^{-9}) Before Fracturing	After Fracturing	6 Months After Fracturing	2 Years After Fracturing
MPC	1	High	0.12	150,000	225,000	2.22	8.47	7.37	7.30
	2	High	0.30	52,000	116,000	5.11	7.67	9.52	11.60
	3	High	0.20	160,000	376,000	4.38	35.00	24.00	27.00
	4	High	0.10	134,000	306,000	2.15	22.00	17.63	18.01
	5	High	0.09	160,000	375,000	0.93	3.53	1.86	1.40
LPC	9	Low	0.03	315,000	288,000	1.14	9.91	3.64	1.93
	10	Low	0.05	119,000	88,000	1.50	16.80	5.29	6.05
	11	Low	0.20	118,000	100,000	0.76	0.91	0.78	0.24
	12	Low	0.10	117,000	100,000	1.13	3.08	2.74	1.62
	13	Low	0.03	94,000	52,000	0.50	2.71	0.85	0.33
	14	Low	0.30	508,000	400,000	2.00	16.01	13.94	9.32
	15	Low	0.20	180,000	150,000	0.78	10.46	5.12	3.94
	16	Low	0.20	204,000	200,000	0.33	2.63	1.71	0.48
	17	Low	0.30	210,000	210,000	0.44	11.08	15.81	7.05
	18	Low	0.25	219,000	300,000	4.96	65.81	19.56	10.99
	19	Low	0.10	80,000	76,000	1.82	5.31	1.12	1.02
	20	Low	0.30	200,000	200,000	1.43	24.07	17.67	6.78

Case History II – Wilcox-Lobo Sand

Case History II comes from a study conducted on wells stimulated in the Wilcox-Lobo sands in South Texas. Like the Vicksburg sand, the Wilcox-Lobo is a deep, hot reservoir with a bottomhole temperature of about 300°F. In this study, post fracture build-up tests and production data history matching were used to compare the success of high proppant concentration fracture treatments (HPC) and medium proppant concentration treatments. (MPC) The high proppant concentration treatments (HPC) averaged about 3 million pounds of proppant while the medium proppant concentration treatments (MPC) averaged about 350,000 pounds of proppant. As can be seen in **Fig. 6,** the high proppant concentration treatments resulted on average in longer fracture lengths. The longer fracture lengths resulted in increased drainage areas, reserves, and deliverability as shown in **Fig. 7a**, **Fig. 7b**, and **Fig. 7c**. Data used to generate these graphs can be found in **Table 4**. This case history shows an example where higher proppant volumes contribute to longer fractures which contacted more reservoir, and increased the volume of gas in contact with each well.

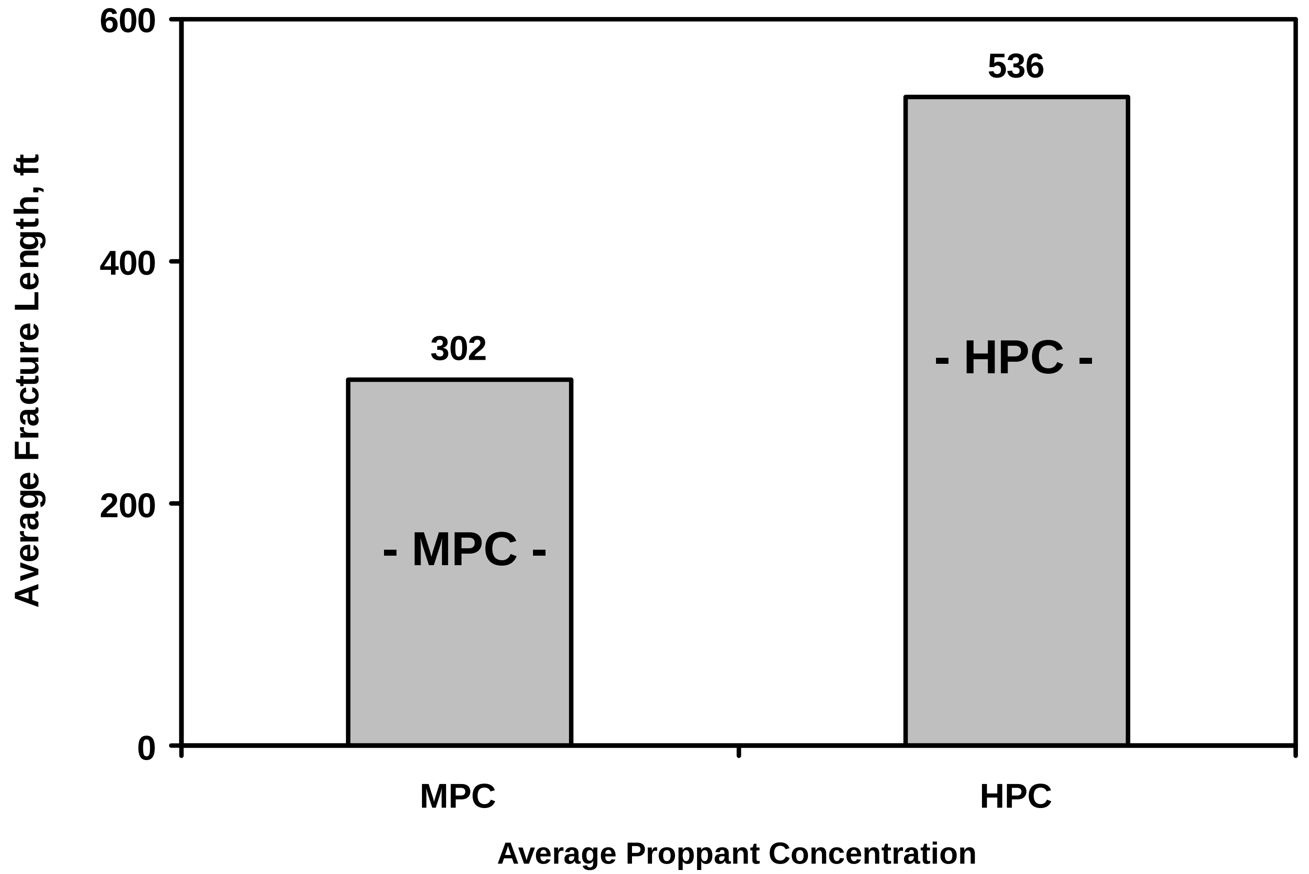


Fig. 6 – Fracture Length and Treatment Sizes in the Wilcox-Lobo Sand

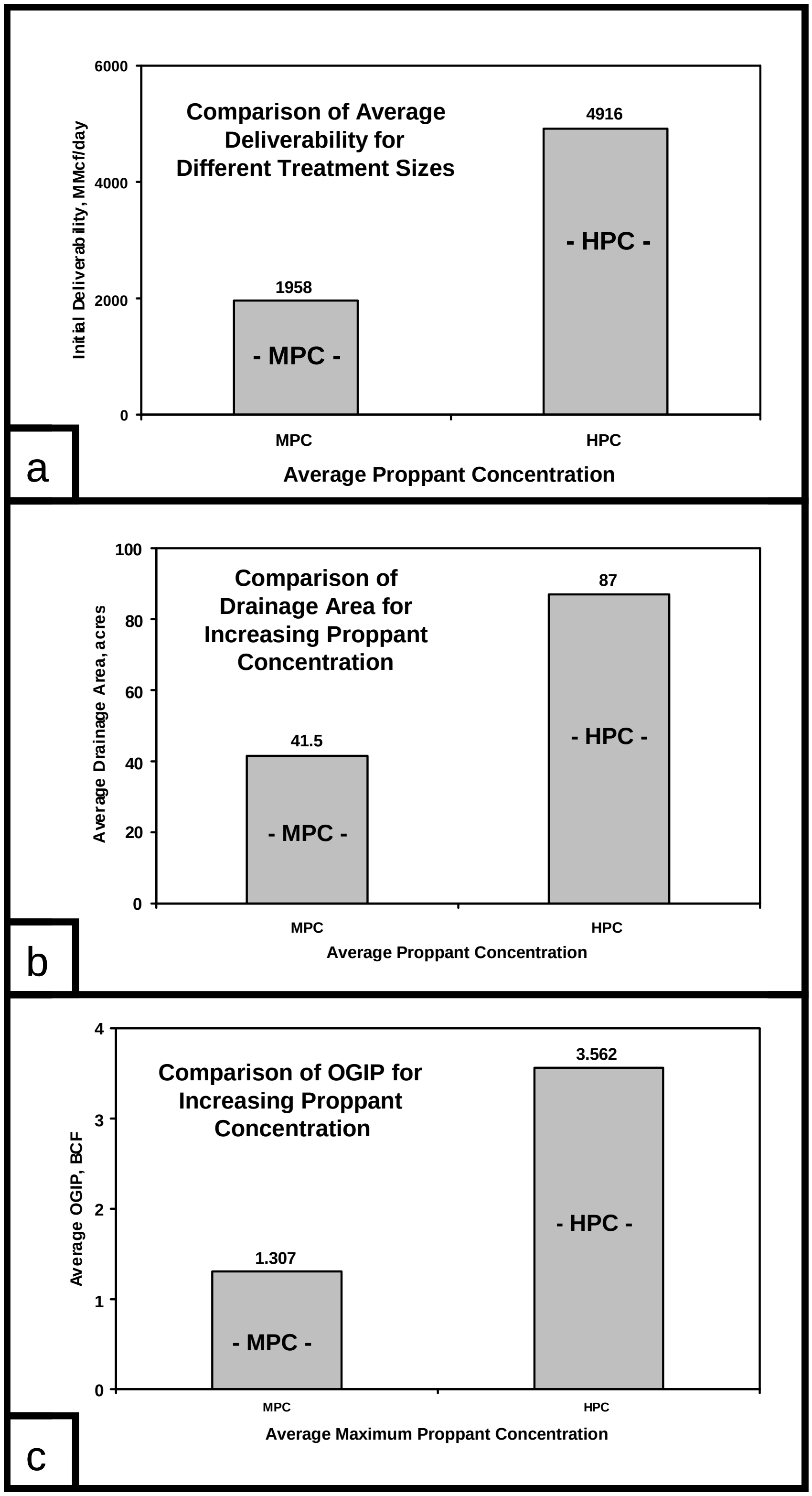


Fig 7. – Results of Large Treatments in the Wilcox-Lobo Sand

Table 4 – Wilcox-Lobo Case History Data

Treatment Size	Well	Proppant Quantity (lbs)	Lf (ft)	Gas Porosity (fraction)	k (md)	hp (ft)	Drainage Area (acres)	OGIP (BCF)
MPC	1	777,000	466	0.1314	0.040	39	20	1.34
	2	185,000	230	0.1000	0.030	24	43	1.40
	3	108,000	100	0.0966	0.100	10	8	0.10
	4	242,000	150	0.1000	0.047	18	29	0.72
	5	199,700	375	0.0650	0.017	24	100	2.75
	6	325,000	350	0.0690	0.018	15	30	0.35
	7	506,000	750	0.0720	0.110	70	60	3.35
	8	1,542,000	320	0.1150	0.013	38	9	0.51
	9	434,000	250	0.1092	0.150	16	51	1.18
	10	341,000	280	0.1210	0.075	34	7	0.38
	11	480,000	180	0.1060	0.010	15	3	0.06
	12	218,500	325	0.1050	0.024	17	20	0.48
	13	490,000	150	0.0850	0.220	25	160	4.37
HPC	14	4,351,000	500	0.1214	0.060	63	80	7.90
	15	4,360,000	567	0.0882	0.030	30	30	1.12
	16	3,218,000	450	0.0791	0.100	33	160	5.11
	17	3,489,000	400	0.1091	0.150	25	160	5.24
	18	3,471,500	365	0.1230	0.100	45	12	0.81
	19	2,772,000	933	0.1166	0.100	49	80	5.53

Case History III – Bossier Sands

In this case history, Rushing and Sullivan[17] presented a progression of fracturing techniques used by Anadarko Petroleum Company to optimize stimulation in the low-permeability Bossier sands in the East Texas basin. The Bossier sands occur at depths between 12,000 and 15,000 ft. Reservoir temperature of these sands is about 300°F. **Fig. 8** summarizes the progression of stimulation techniques and the results obtained as new techniques were implemented. Initially, large proppant volumes transported with high concentration, cross-linked polymer fluids were used to stimulate the Bossier sands. Evaluation of poor post treatment well performance suggested that the high proppant concentration, high viscosity treatments were resulting in short effective fracture lengths. Rushing and Sullivan[17] suggested that this was '…a result of both uncontrolled fracture height growth and gel damage in the fracture.'

To mitigate the problems cause by the high proppant volume, high polymer concentration treatments Anadarko tried using waterfrac technology with no proppant. Results were similar to the former treatments. Better results were obtained subsequently with low proppant volume waterfracs; however, the effective fracture lengths were still too short for this low-permeability reservoir. Significant improvements were obtained later with smaller proppant sizes and high proppant volume waterfracs. Anadarko then began using 'hybrid' fracture treatments.

Hybrid fracture treatments combine the assets of both waterfrac technology and conventional gel fracture treatments to optimize fracture stimulation. Hybrid fracture treatments utilize the ability of slickwater to create long fractures without excessive fracture height growth to create the geometry of the fracture during the beginning stages of the treatment. Cross-linked gels at low polymer concentrations are used to transport proppant deeply and uniformly into the fracture after the fracture geometry has been created by the slickwater in the later stages of the treatment.

Rushing and Sullivan[17] used a combination of short-term pressure build-up analysis and long term production analysis to history match wells stimulated with waterfracs and wells stimulated with ‘hybrid’ fracture treatments. As shown in **Fig. 9a** and **Fig. 9b**, Rushing and Sullivan[17] found that the wells stimulated with viscous cross-linked fluids resulted in longer fracture lengths and higher fracture conductivities than waterfracs.

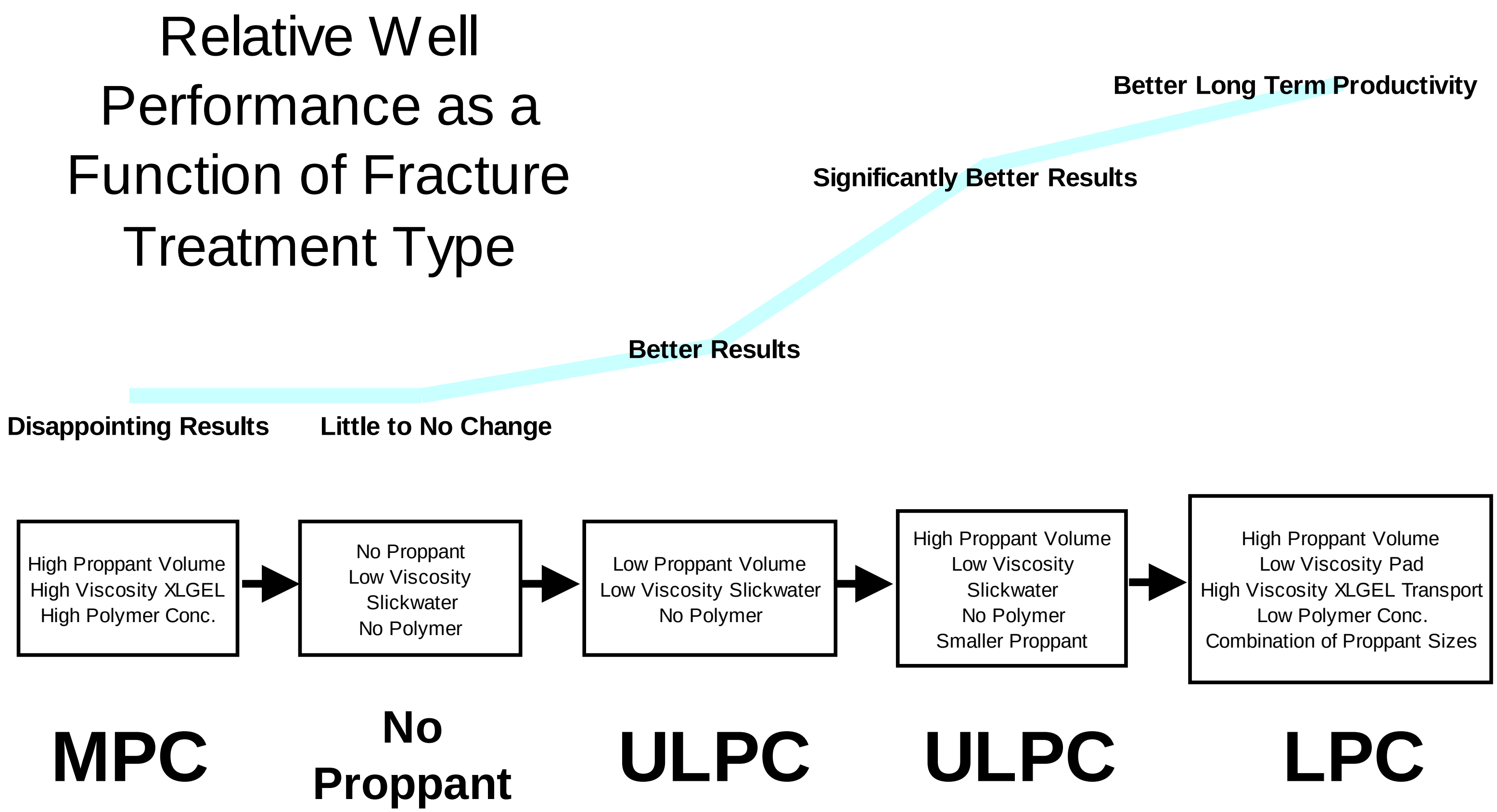


Fig. 8 – Refining Stimulation Practices in the Bossier Sands (Data from Rushing and Sullivan[17])

Data used to generate Fig. 9a and Fig. 9b can be found in **Table 5**. Sharma *et al.*[18] showed that the wells stimulated with viscous cross-linked fluids also maintained higher sustained production rates. **Fig. 9c** was generated with an analytical simulator using data from Rushing and Sullivan's[17] paper for each treatment size. If a geometric average of the reservoir permeability is taken for all of the wells to be about 0.022 md, it can be seen that the hybrid treatments make much more gas in 10 years than the other treatments. The progression of stimulation techniques in the Bossier sands clearly shows that viscous cross-linked fluids can be used to effectively place more proppant in the fracture to create better wells than low viscosity, low proppant volume treatments when the fluids are optimized for conditions. It also shows, however, that cross-linked fluids can significantly damage and reduce well performance when these fluids are not appropriately used.

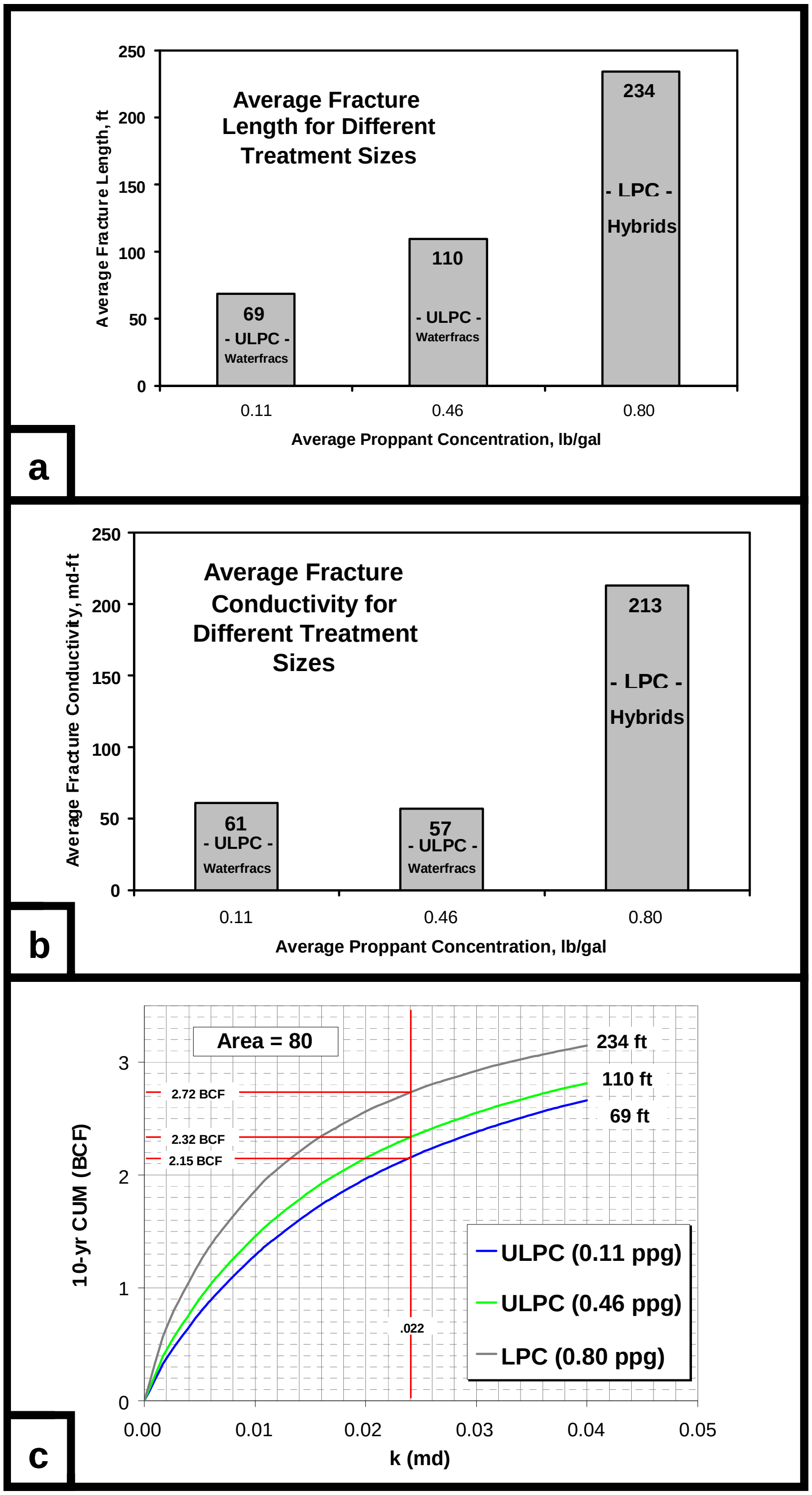


Fig. 9 – Treatment Results in the Bossier Sands (Data from Rushing and Sullivan[17])

Table 5 – Bossier Sands Case History Data (From Rushing and Sullivan[17])

Treatment Size	Treatment Type	Proppant Qty (lbs)	Fluid (bbl)	k (md)	Lf (ft)	w-kf (md-ft)
ULPC	WATER	34,000	7,460	0.019	73.9	220.6
	WATER	30,000	7,845	0.012	108.9	141.7
	WATER	33,000	7,000	0.034	52.0	127.0
	WATER	28,605	5,281	0.013	44.1	13.8
	WATER	17,260	3,962	0.009	63.6	15.7
ULPC	WATER	168,400	9,712	0.618	97.1	906.3
	WATER	170,000	10,083	0.024	63.8	26.8
	WATER	237,000	8,175	0.027	235.3	250.9
	WATER	135,000	9,710	0.019	101.1	16.4
	WATER	180,000	10,076	0.026	28.6	12.3
	WATER	140,000	8,073	0.035	140.8	29.1
	WATER	360,000	15,481	0.019	100.4	56.8
LPC	HYBRID	191,000	6,650	0.144	289.5	977.6
	HYBRID	100,000	8,404	0.009	268.4	40.8
	HYBRID	248,000	7,300	0.013	119.9	375.7
	HYBRID	225,000	7,757	0.009	313.2	537.4
	HYBRID	440,580	6,958	0.004	124.5	62.5
	HYBRID	299,000	8,504	0.028	290.1	185.2

Case History IV – Cotton Valley Sands

Case History IV is an integration of several publications regarding fracture stimulation of the Cotton Valley sands in the East Texas basin. The Cotton Valley sands are low-permeability sands occurring throughout East Texas and North Louisiana at depths anywhere from about 8400-10,500 ft. Reservoir temperature in these sands ranges from 225-275°F.

Mayerhofer and Meehan[6] compared 6-month cumulative production for wells stimulated with waterfracs and wells stimulated with conventional large proppant volume, cross-linked gel treatments. Aproximately 90 wells were evaluated from 3 fields in the East Texas basin. All of the wells were completed in the Cotton Valley sands. Mayerhofer and Meehan[6] grouped the wells by field and generated cumulative probability plots of the 6-month cumulative gas production for each treatment type. The 6-month cumulative production distributions for every field showed little to no difference between the different treatment types. Mayerhofer and Meehan[6] concluded that wells stimulated with waterfracs performed as good and in some cases better than conventional treatments. They also concluded that since the cost of a waterfrac is less than a cross-linked gel fracture treatment, that waterfracs should be used in the Cotton Valley sands. Materhofer and Meehan[6] hypothesized that gel damage in the conventionally fractured wells may be a possible reason the wells performed comparably. This study appears to resemble similar experiences with gel usage in the Bossier sand as described in Case History III.

Mayerhofer and Meehan[6] compared wells solely on the basis of production data and did not determine any fracture or reservoir properties. Following Mayerhofer and Meehan's[6] publication, England, Poe, and Conger[16] presented results from a study conducted on 10 pairs of wells stimulated with waterfracs and conventionally stimulated offsets. In this study England, Poe, and Conger used history matching techniques to determine gas permeability, fracture length, drainage area, and fracture conductivity for each pair of offsets. Conventionally stimulated wells resulted on average in longer fracture lengths, higher fracture conductivities, and larger drainage areas. England, Poe, and Conger[16] estimated that conventionally fractured wells produced on average 38.5 % more gas than wells stimulated with waterfracs when production data was normalized on the basis of hydrocarbon column and pressure drawdown. England, Poe, and Conger[16] concluded that viscous fluids and large proppant volumes were needed to stimulate tight sands like the Cotton Valley.

Willberg *et al*.[20] quantitatively evaluated the fracture clean-up of wells stimulated with cross-linked fluids and high proppant volumes in the Cotton Valley sands by measuring polymer returns. In this study, polymer returns were measured during flowback for 10 wells stimulated with borate and zirconate cross-linked gels. Willberg *et al*.[20] found that on average only 35% of the polymer pumped into the wells was being recovered during the flow back following the fracture treatments. These low values of returned polymer were found to be comparable to returns determined in similar studies in other tight gas sands. However, polymer returns significantly reduced after the wells were placed on production. Willberg *et al*.[20] found that after the wells were put on production only minimal if any polymer would be produced from the well. Optimistically, 3% of the total polymer pumped may be returned per year after the wells were put on production. This means that after 5 years, on average, 50% of the total polymer pumped will still be in the fracture.

Craig[21] evaluated breaker concentrations required to effectively break cross-linked fracture fluids at various pH levels and temperatures. Craig[21] found that polymer chains in cross-linked fluids do not completely break unless the viscosity of the fluid reduces to 3 cP or less. Craig[21] found that the amount of necessary breaker concentration that is required to completely break cross-linked fluids increases as reservoir temperature decreases. **Table 6** shows how much breaker is necessary to completely break the polymer chains in cross-linked fracturing fluids at various temperatures.

Craig's[21] results have some interesting implications for fracture fluid selection in the Cotton Valley. In low temperature reservoirs like the Cotton Valley, very high breaker concentrations are necessary or cross-linked fluids used in these reservoirs will never completely break and clean up. However, if breaker concentrations this high are used, the cross-linked fluids will break before they reach the fracture and the treatment will screen-out. Either scenario results in less than optimal stimulation.

Table 6 - Required Breaker Concentrations for Neutral pH HPG Gels*(From Craig[21])

Temp (DEGF)	Oxidizer Breaker (lbm/1000-gal)
120	3.0
130	3.0
140	2.4
160	2.0
180	2.0
200	2.0
220	2.0
240	1.8
260	1.0
280	1.0

*Titanate Cross-linked 40 lb/1000-gal HPG gel

Summary of Case Histories

Many of these case histories show that larger treatments and higher proppant concentrations are required to optimally stimulate tight gas sand reservoirs. When large treatments and high concentrations are not successful it is typically because the fracturing fluids have not been optimal for the application. High temperature reservoirs (300°F) like the Bossier, Vicksburg, and the Wilcox-Lobo appear to respond favorably to large treatments using viscous polymer-based fluids. Lower temperature reservoirs like the Cotton Valley (225-275°F) appear to have less than optimum results when viscous cross-linked polymers are used. Drawing on what has been shown from the previous case histories, it is likely that poor performance of cross-linked polymer treatments carrying large volumes of sand in the Cotton Valley is largely due to fluids that are not optimal for Cotton Valley conditions. In other words, the gels do not contain enough breaker and, thus, the fracture fluids are damaging the fracture and not cleaning up properly.

CARTHAGE COTTON VALLEY STUDY

Sample Groupings and Pre-Evaluation

The Carthage field located in East Texas was chosen for this study because it has a long history of various treatment sizes and because it was one of the first fields where waterfracs were used extensively to stimulate tight sands. Wells were grouped by treatment sizes. An area of interest within Carthage field was selected with an excellent distribution of treatment sizes. As shown in **Fig. 10**, the area of interest spans about 10 miles east-west and about 10 miles north-south. Typically wells in this area are stimulated with two to four stage treatments. The typical completion technique is to first perforate and fracture stimulate the lower most Cotton Valley sand known as the Taylor sand. This interval is isolated using a bridge or sand plug. The shallower intervals of the Cotton Valley known generally as the Upper Cotton Valley are then perforated and stimulated using two to three separate stages isolating each previously stimulated stage as described earlier. All of the Cotton Valley intervals are then commingled and placed on production following flowback.

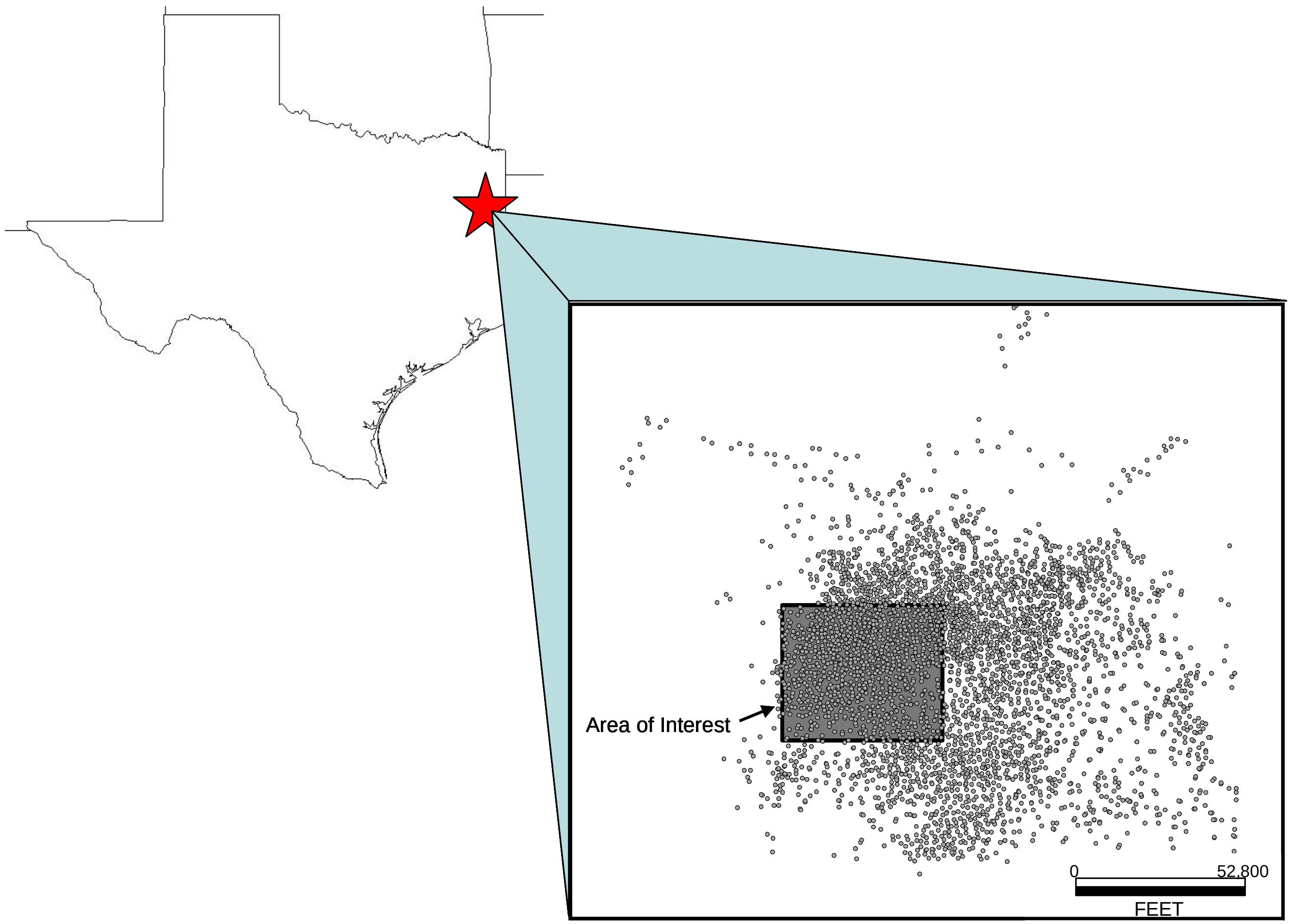
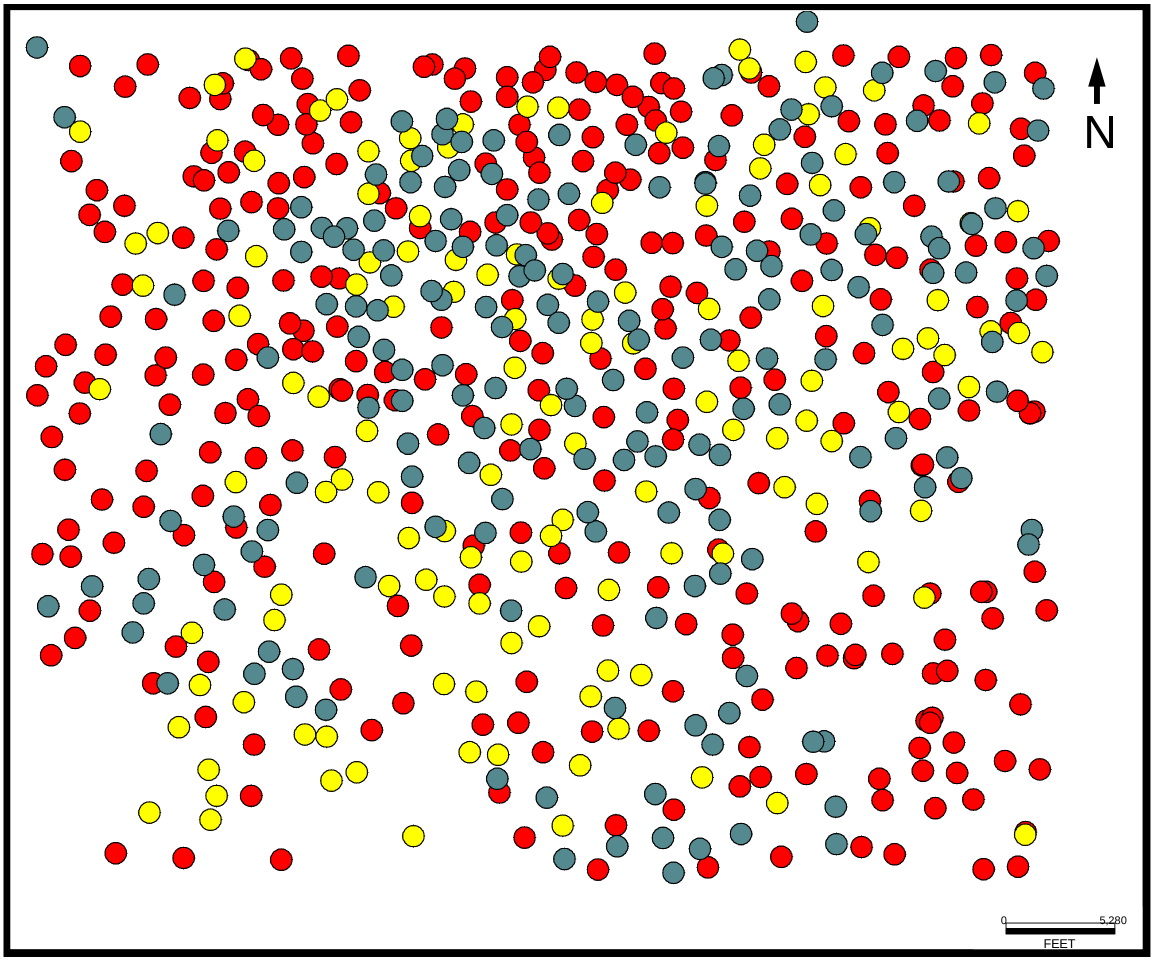


Fig. 10 – Carthage Field and Area of Interest

Because multiple treatments are used in this area, treatment size was based on the average proppant concentration determined from the total proppant pumped and the total fluid pumped for all stages to allow comparison from well to well. **Table 7**, shown below, indicates how the treatment sizes were identified based on concentration. The colors corresponding to each treatment size will be used in subsequent figures to identify treatment sizes. Treatment information was found for approximately 630 wells in the area of interest. As seen in **Fig. 11**, this area has a very good distribution of all treatment sizes designated in Table 6.

Table 7 – Treatment Size Designations for Cotton Valley Study

Ultra-low Proppant Concentration (ULPC)	**< 1 ppg**
Low Proppant Concentration (LPC)	**1-2 ppg**
Medium Proppant Concentration (MPC)	**2-6 ppg**



Ultra-low Proppant Concentration (ULPC)	**< 1 ppg**
Low Proppant Concentration (LPC)	**1-2 ppg**
Medium Proppant Concentration (MPC)	**2-6 ppg**

Fig. 11 – Treatment Size Distribution Within Area of Interest

The Carthage field has undergone significant development drilling and a progression of decreased well spacing requirements over the last 25 years. The well sample was divided into groups by first production date on the basis of similar initial reservoir pressures and well performance so that depletion would not unduly influence the comparison of the different treatment sizes. The average gas flow rate for the Best Year was determined for every well in the interest area. The Best Year is the best 12 consecutive months of production as shown in **Fig. 12**. It has been shown that long term performance of tight gas sands has a good correlation with the average rate of the Best Year.[22-24] This correlation can be seen by observing relationship between the Best Year average rate and the cumulative 5-year gas production for every well in the interest area shown in **Fig. 13**. **Fig. 14** is a graph of the day of first production versus the Best Year average rate for all of the wells in the interest area grouped by treatment sizes. As seen in Fig. 14, the general trend shows that the Best Year average rate tends to decrease over time for all wells throughout the development of the field. **Fig. 15** is a similar plot showing the initial reservoir pressure for all wells throughout the development of the field. Initial pressure decreases throughout the development of the field as well. The general trend of the data in Fig. 14 and Fig 15 correlates well. It is clear that depletion is occurring, and the decrease of Best Year average rates over time are being influenced by the declining reservoir pressure.

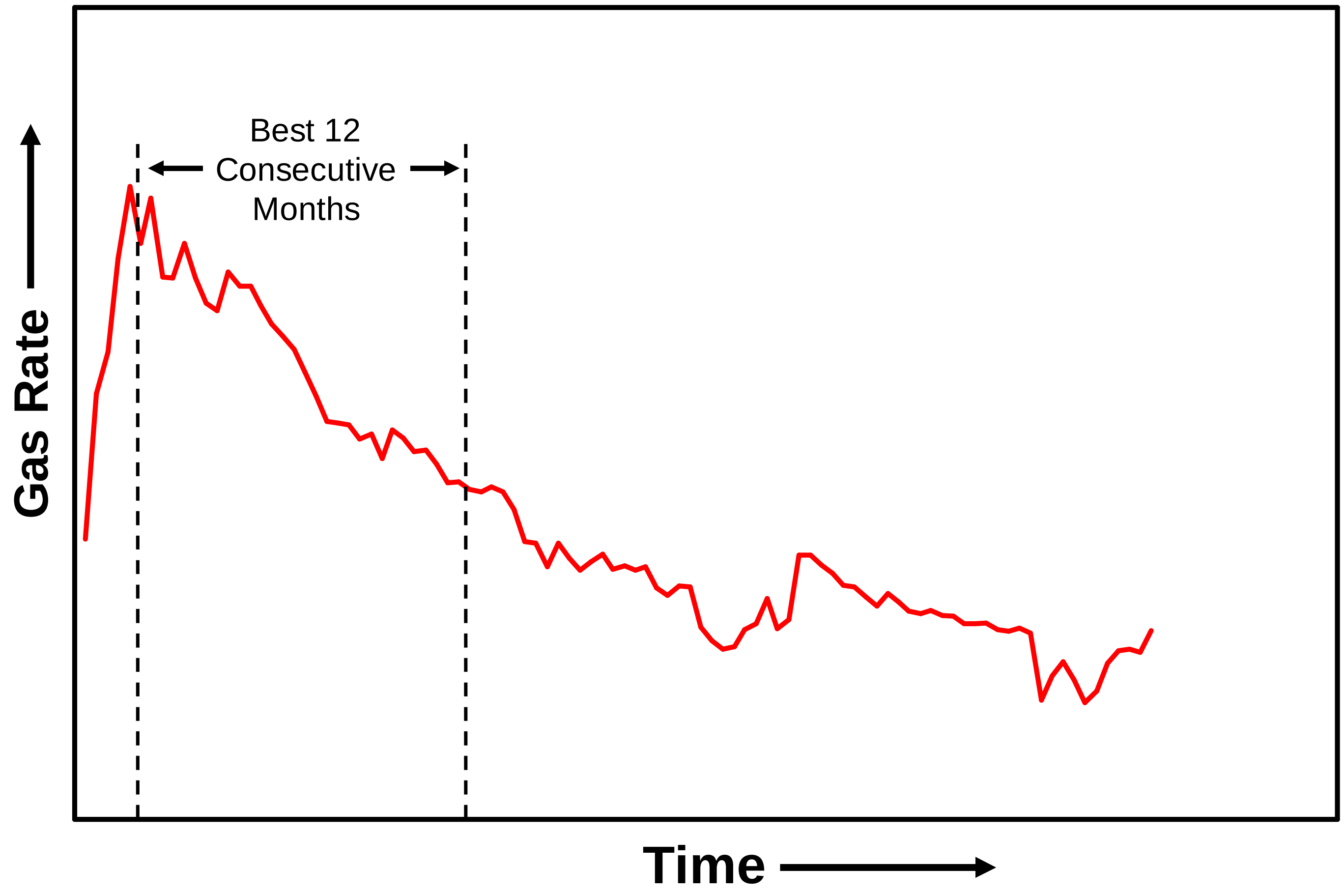


Fig. 12 – Determination of Best Year (From Hudson, Jochen, and Jochen[22])

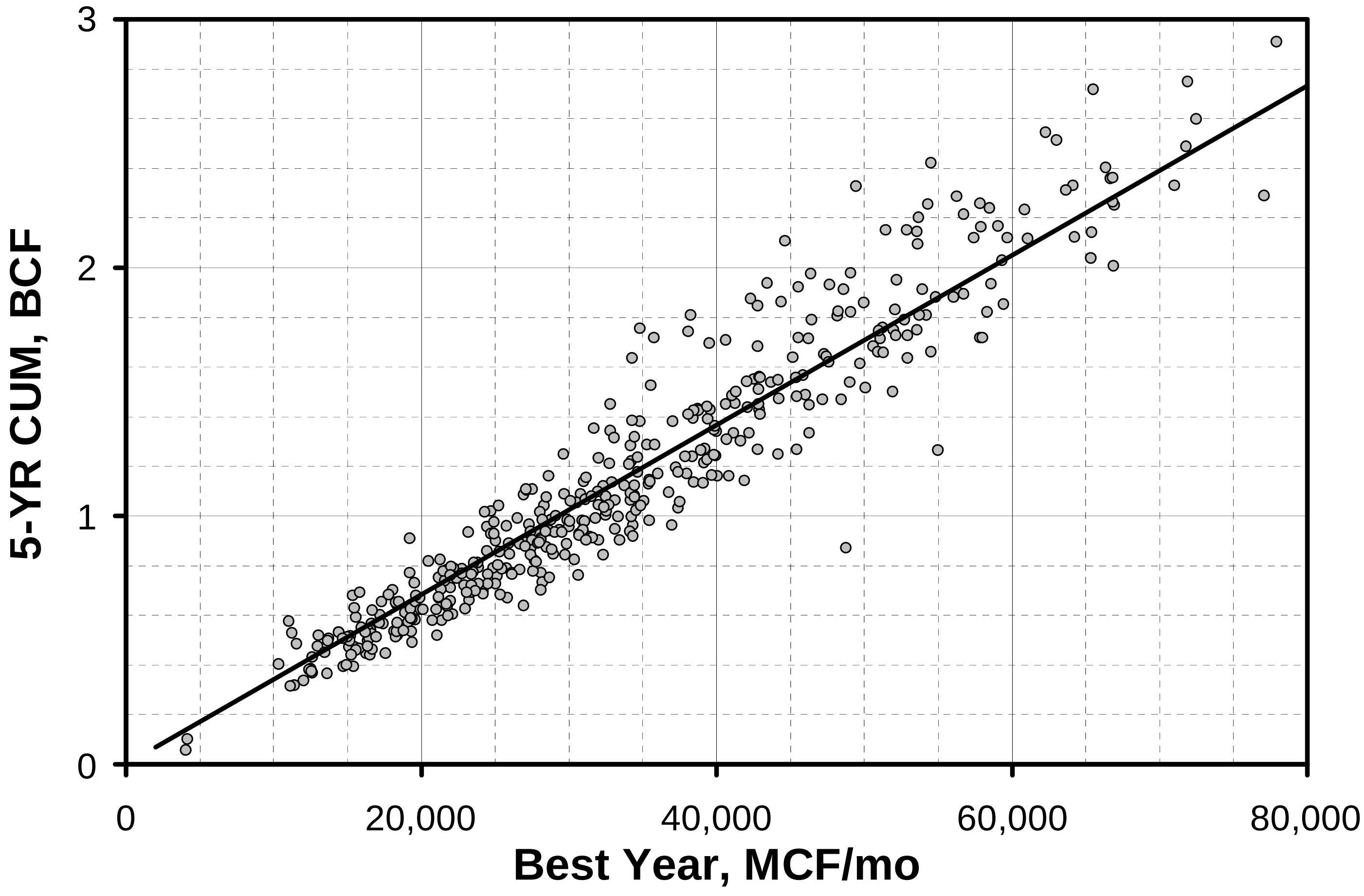


Fig. 13 – Example of Best Year Average Rate and Long-term Production Correlation for Wells in Interest Area

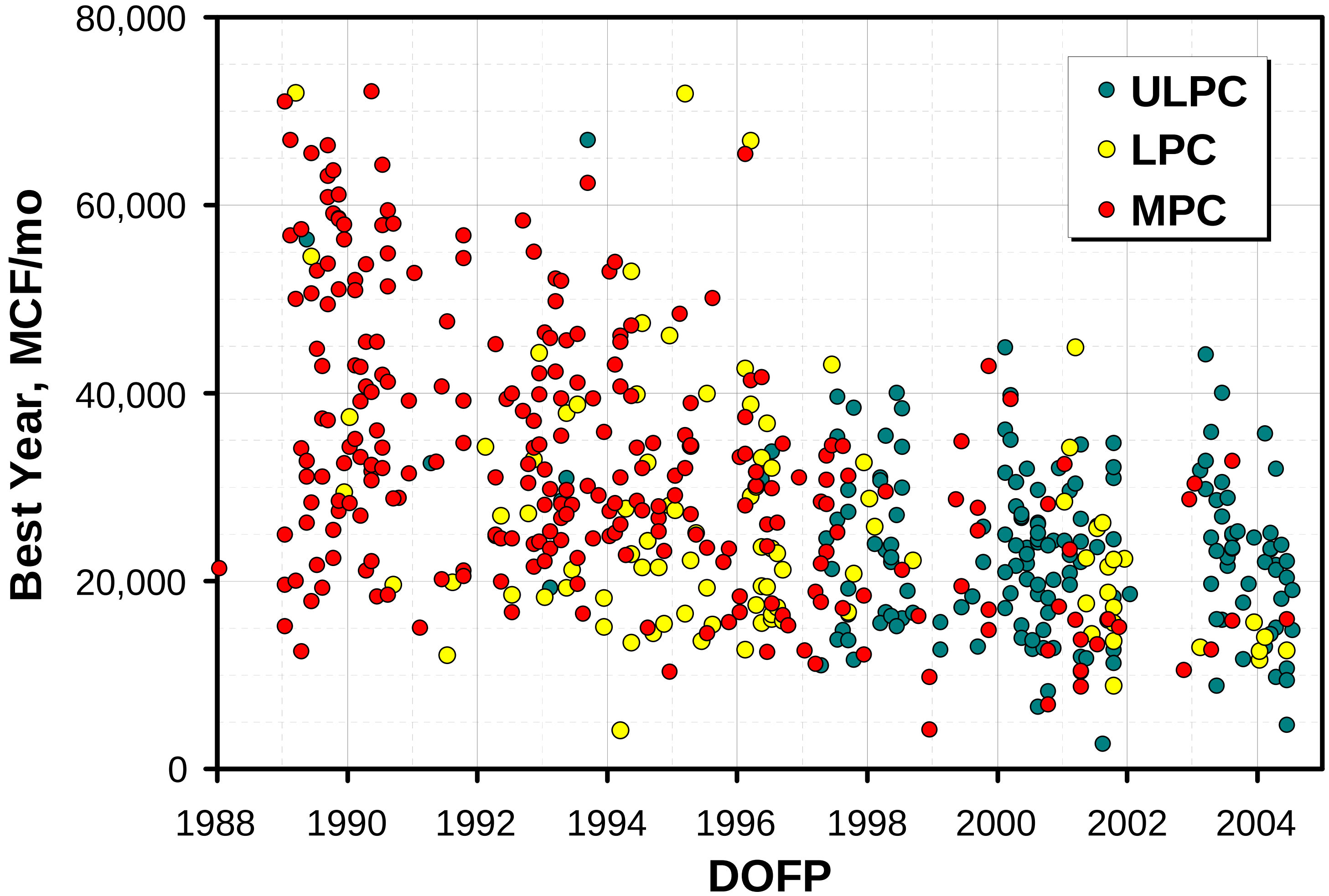


Fig. 14 – Trend of Best Year Average Rate Throughout Development of Interest Area

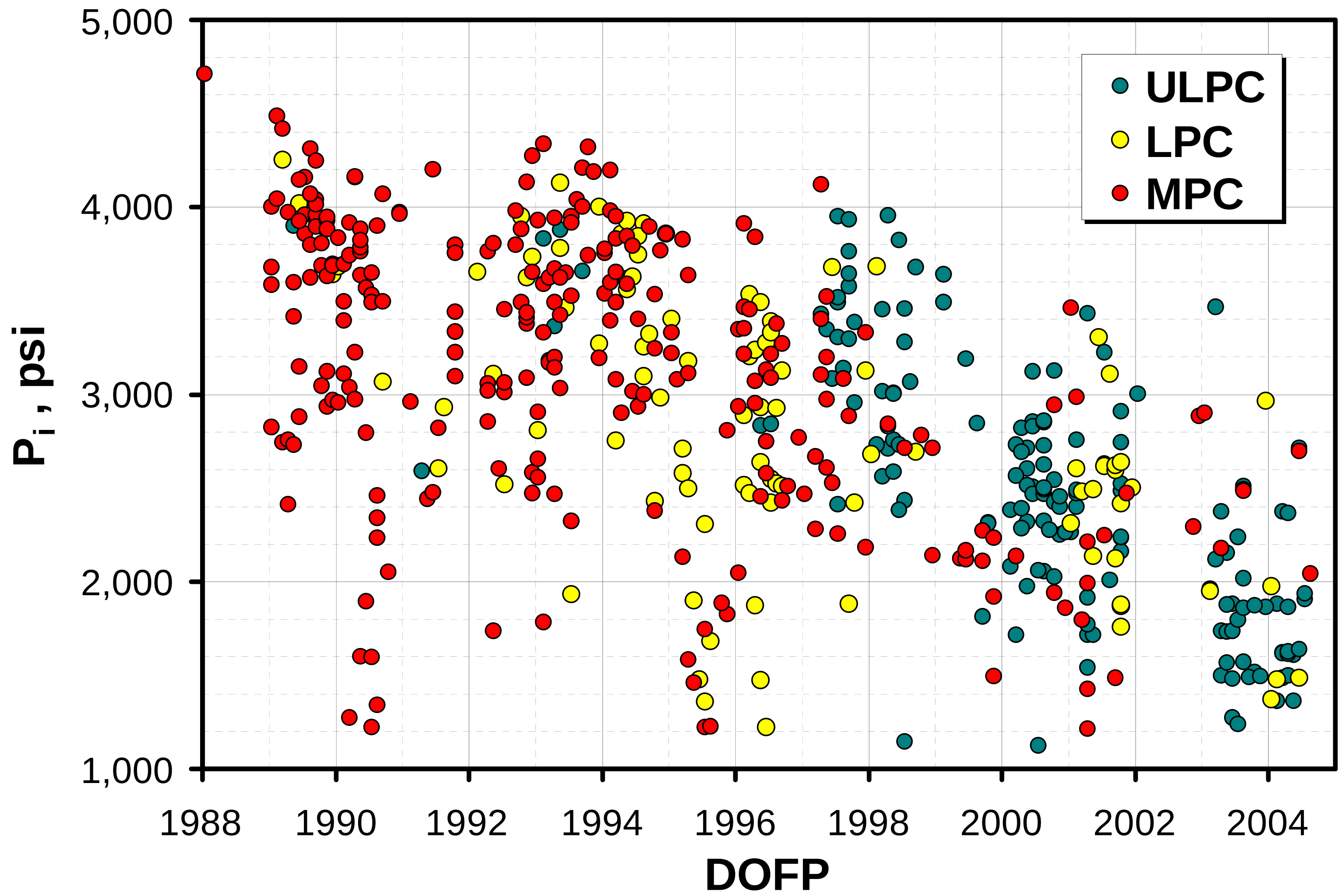


Fig. 15 – Example of Depletion Over the Course of Development of Interest Area

As discussed previously, the well sample was sub-divided into groups by similar first production dates to minimize the influences of depletion when comparing fracture treatment types. Four groups were selected using the data in Fig. 14 and Fig. 15, by selecting time periods in the field development with similar distributions of initial pressure and Best Year average rate. The selected groups are designated below in **Table 8**.

Table 8 – Well Groupings by Time Period

Group I	1989 - 1992
Group II	1993 - 1995
Group III	1996 - 1998
Group IV	1999 - 2001

Fig. 16 is a cumulative probability graph of the Best Year average rate determined for each group. The trend of decreasing Best Year average rate over time can be more clearly seen by the distinct shifts in the cumulative probability curves for each time period in Fig 16. Referring again to Fig. 14 and Fig. 15, it can be seen that the time periods for Group III and Group IV appear to have the most diverse distribution of treatment sizes. These groups were subsequently selected for more detailed analysis. Treatment statistics for the treatment sizes in Group III and IV are shown in **Table 9**.

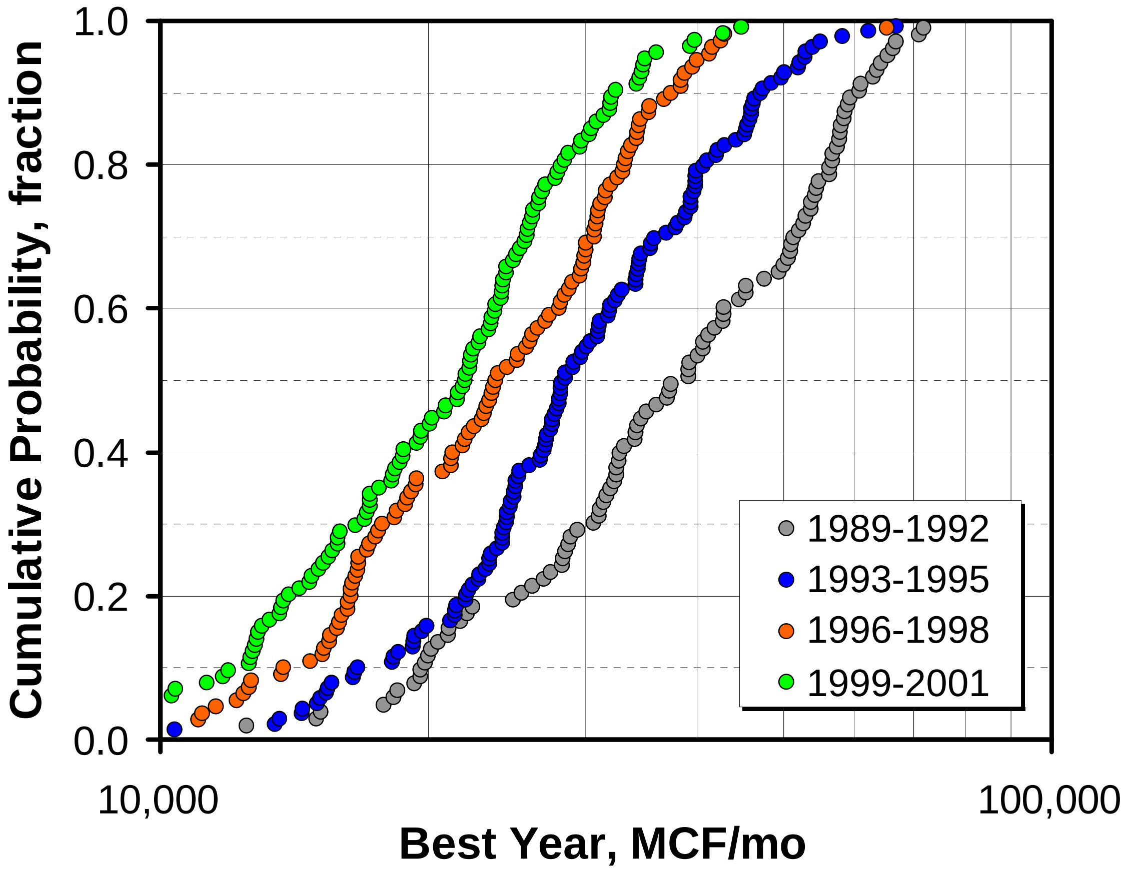


Fig. 16 – Distribution of Well Quality Over Time

Table 9 – Treatment Statistics for Evaluated Well Groups

Group	Treatment Size	Avgerage Proppant Quantity (lb)	Avgerage Fluid Volume (bbl)	Avgerage Proppant Conc. (lb/gal)
III	ULPC	297,350	19,987	0.38
	LPC	1,190,363	16,438	1.74
	MPC	1,396,515	11,908	2.80
IV	ULPC	363,373	20,092	0.42
	LPC	820,110	12,979	1.52
	MPC	1,098,954	11,324	2.36

Production Data History Matching

Attempt was made to determine values for permeability, fracture length, fracture conductivity, and drainage area for wells in Group III by history matching production data reported in the public domain. Unfortunately, it was very difficult to obtain unique solutions using this method when one is trying to determine permeability, fracture conductivity, drainage area, and fracture length simultaneously. **Fig. 17a** and **Fig. 17b** show an example of very good matches of long term production data matched with completely different values of fracture length and gas permeability. Note the magnitude of difference in permeability and fracture length for both matches. Gas permeability in the Cotton Valley sands can range anywhere from 0.005 to 0.05 md. Within this range, an incorrect estimation of permeability can have a significant effect on the estimated fracture length as shown in Fig. 17a and Fig. 17b making comparison of history matches for different treatment sizes inconclusive. Others have encountered similar problems and found that obtaining unique solutions requires a prior knowledge of gas permeability obtained from pre-stimulation well tests or post-fracture buildup tests.[25] When these tests are unavailable, it has been found that daily rate-pressure data can be sometimes used to address non-unique solutions.[15] Unfortunately, these tests are rarely performed in this field and daily rate-pressure data was unavailable for this study. In lieu of this issue, a method using a combination of well performance indicators, analytical simulation, and basic statistical analysis was used to compare the performance of wells stimulated with the different treatment sizes in Group III and Group IV.

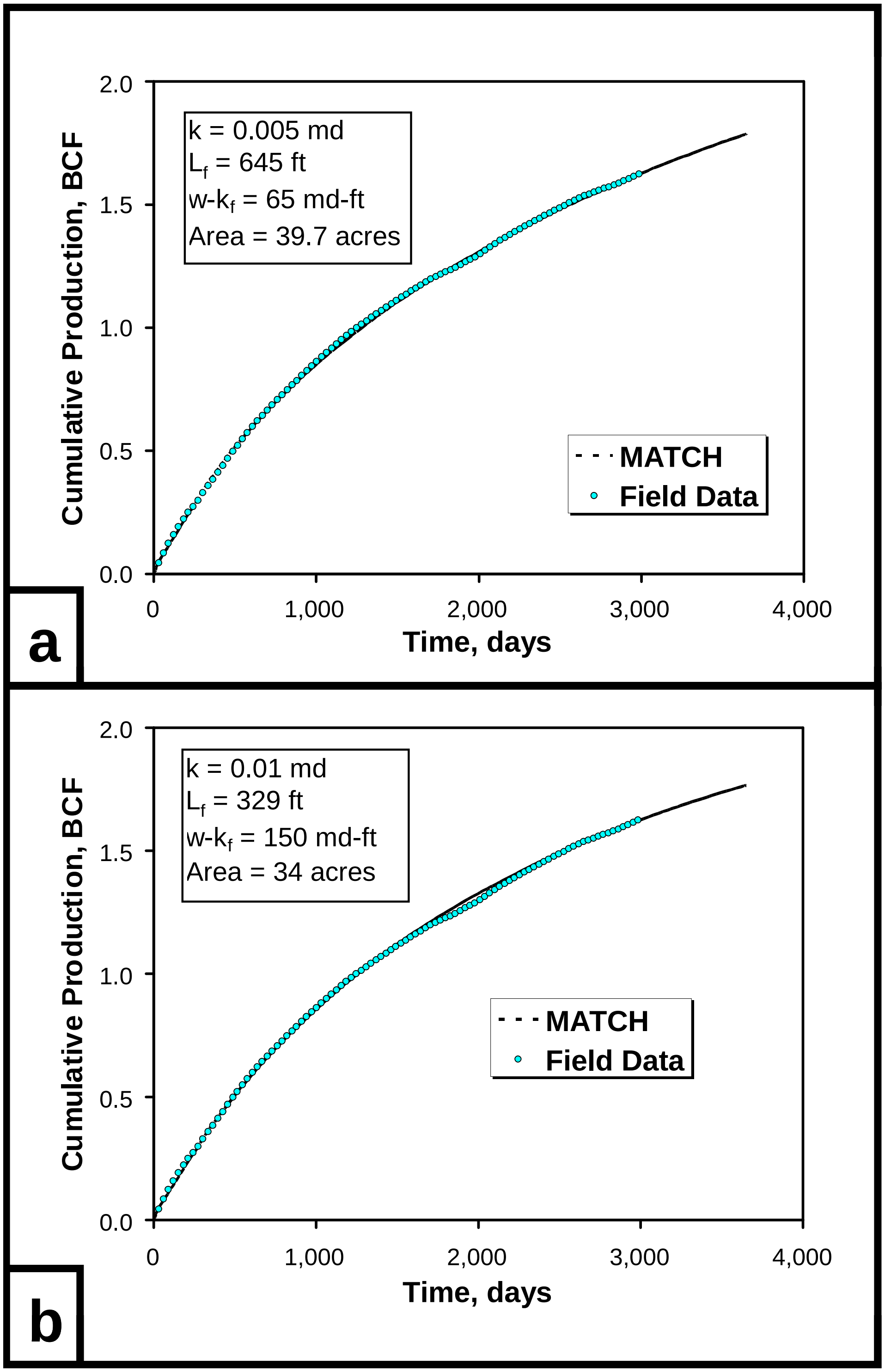


Fig. 17 – Inconclusive History Matching

Methodology

Theoretical Framework

The method used to evaluate the different treatment sizes will be explained graphically using a hypothetical example of production statistics. As mentioned previously, the Best Year average rate has been shown to have a good correlation to long-term production. **Fig. 18a** is an example plot of Best Year average rate versus 5-year cumulative gas production for a hypothetical sample of wells stimulated with similar treatments. Assuming the wells have been stimulated similarly and the stimulation treatments have relatively consistent success, the distribution of well quality should primarily be dictated by the distribution of reservoir quality within the interest area. As seen in Fig. 19a, wells having low values for Best Year average flow rates will also have low 5-year cumulative gas production volumes indicating poor reservoir quality. Wells with higher values for Best Year average rate will have higher 5-year cumulative gas production indicating better reservoir quality. In this case, Best Year average rate is directly related to reservoir quality and will be distributed log normally as reservoir quality typically is as shown in **Fig 18b**.

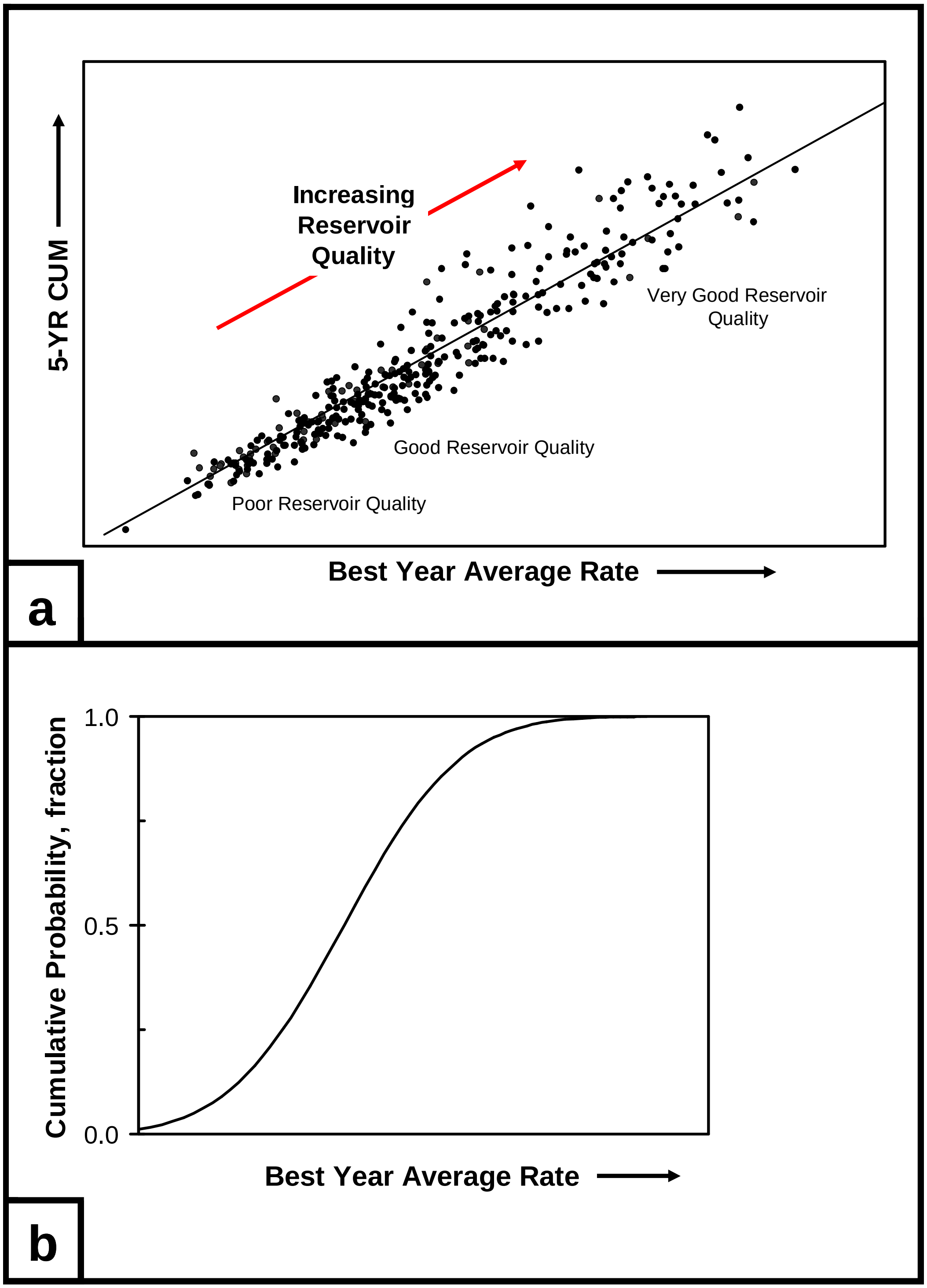


Fig. 18 - Hypothetical Well Quality Distribution

If two different treatments are used to stimulate wells in a particular region of a field the interpretation of the Best Year average flow rate versus the 5-year cumulative gas production will be slightly different. In this scenario, the well sample must be grouped by treatment type because treatment type may have an effect on the distribution and or the correlation between Best Year average flow rate and 5-year cumulative gas production. If, for example, one treatment is more effective than another, a graph of Best Year versus 5-year cumulative gas production may look something like **Fig. 19a**. The overall correlation between Best Year average rate and 5-year cumulative gas production does not change. The reservoir quality is still influencing well quality, but the wells stimulated with Treatment A are on average performing better than wells stimulated with Treatment B. The lower performing wells relative to each group correspond to similar poor reservoir quality. The better performing wells relative to each group correspond to similar better reservoir quality. Best Year average rate will be log normally distributed for each treatment type as in the previous scenario because the overall distribution of reservoir quality will not change from treatment to treatment. However, there should be two distinct distribution curves as shown in **Fig. 19b** because one treatment is resulting in better wells than the other.

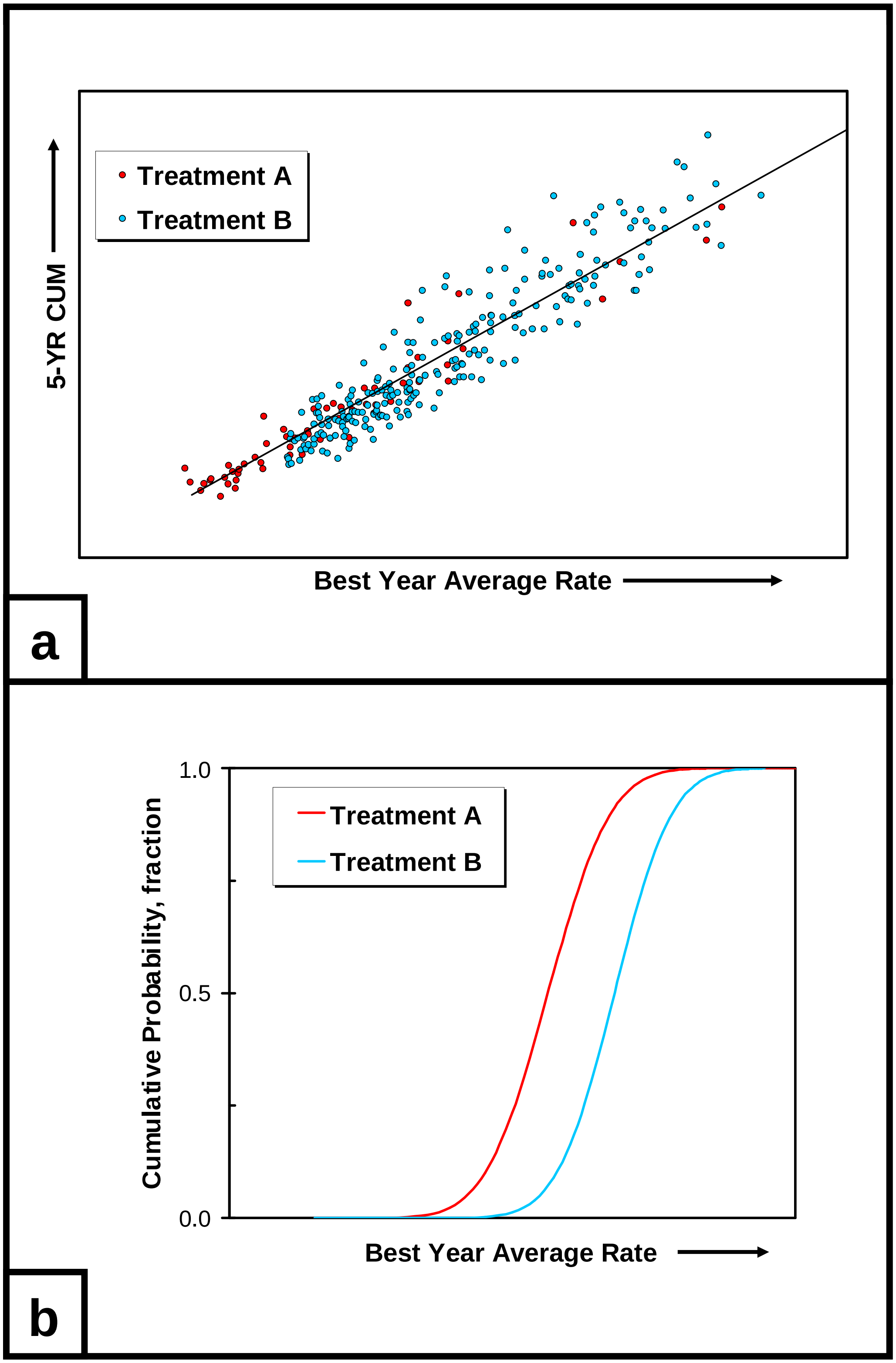


Fig. 19 – Hypothetical Well Quality Given Different Treatment Sizes

Other variations of this scenario could occur. For example, if wells stimulated with both treatments perform comparably early in the production history but one treatment results in wells that have sustained higher long-term production, the Best Year average rate may look something like **Fig. 20a**. In this case, two distinctly different correlations can be seen for each treatment. The distribution of Best Year average rates will be similar regardless of treatments as shown in **Fig. 20b,** but the distribution of 5-year cumulative gas production will show distinctly different curves for the different treatments as shown in **Fig. 20c**.

Application

Similar concepts as discussed in the theoretical framework were used to evaluate and compare the performance of wells stimulated with different treatment sizes in the area of interest. Values for Best Year average rate and 5-year cumulative gas production were determined for every well in Group III. Cumulative gas production was determined up to 5 years because all of the wells in Group III had at least 5 years of production history.

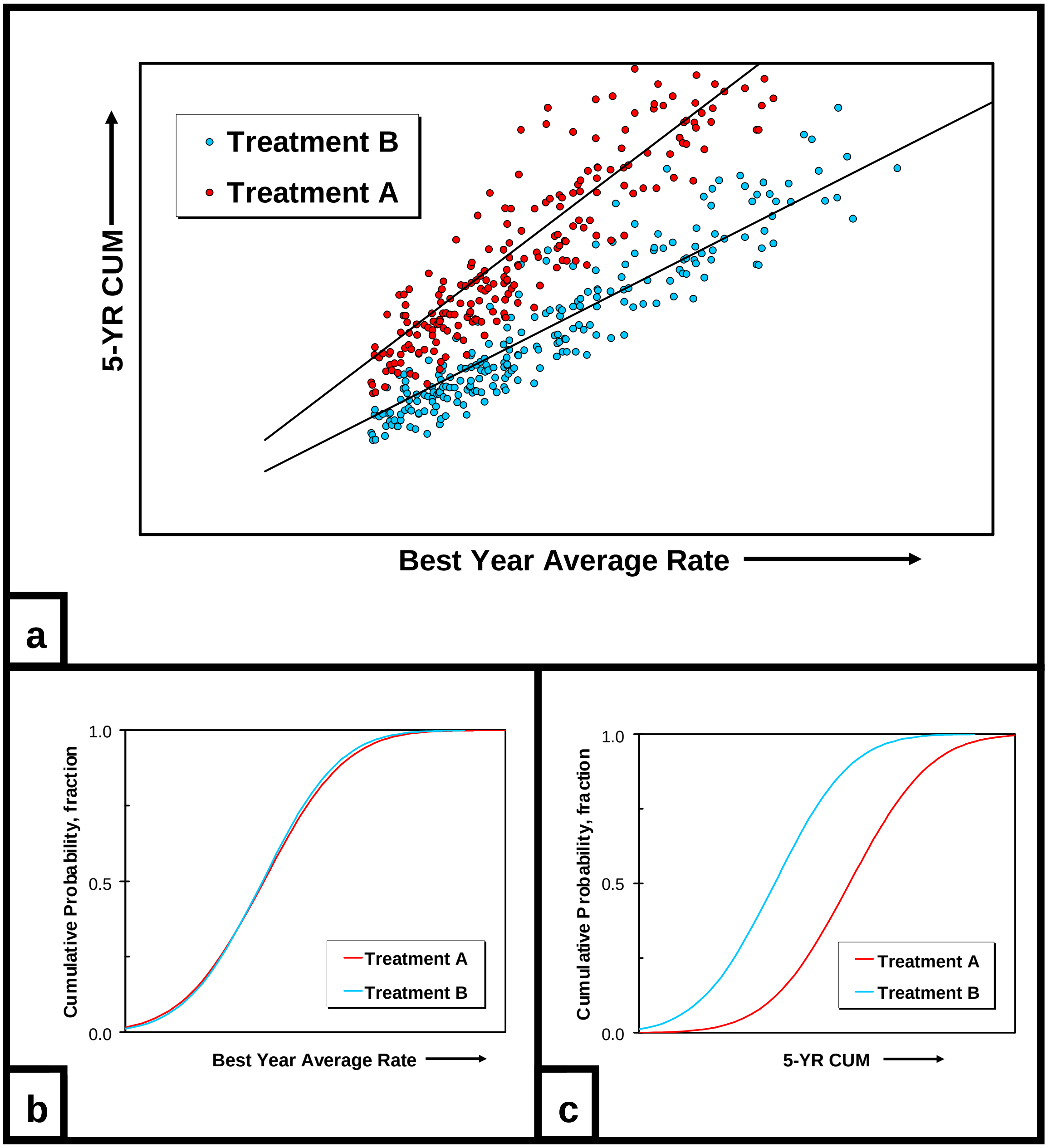


Fig. 20 – Hypothetical Well Quality for Treatments with Different Long-term Performance

Basic statistical analysis was used to generate cumulative probability plots of the Best Year average rate and 5-year cumulative gas production for each treatment size. Group IV was evaluated just as Group III except 3-year cumulative production was used instead of 5-year cumulative production as the wells in Group IV have not produced for 5 years.

Group III was evaluated further by comparing simulated data to the actual field data as Group III had the best distribution of treatment sizes. Values for Best Year average rate and 5-year cumulative production were simulated with an analytical simulator for variations of fracture length, fracture conductivity, drainage area, and gas permeability. The simulations are discussed in more detail in the subsequent section. Simulated values for Best Year average rate and 5-year cumulative production were compared with the actual field data. The distribution of simulated data that matched the general field data distribution was isolated and basic statistical analysis was used to determine the most likely fracture length for the actual field data.

Analytical Simulation

Simulated production data was generated using a single layer, single phase analytical simulator assuming a circular drainage area for all possible combinations of the variables shown below in **Table 10.** Approximately 380 simulations were generated. Flowing bottomhole pressure over time was estimated from the general trend of all wells in Group III and can be found in **Fig. A-1** in the APPENDIX. Other inputs to the model can be found in **Table A-1** in the APPENDIX as well.

Table 10 – Simulation Parameters

k (md)	**L_f (ft)**	**w-k_f (md-ft)**	**Area (acres)**
0.002	100	20	20
0.005	250	100	30
0.010	500	500	40
0.030	750	1000	80
0.050	1000		160

Field Data Results

Fig. 21 is a graph of Best Year average rate versus the 5-year cumulative gas production for all wells in Group III. The wells have been color-coded by treatment size. A cumulative probability plot of Best Year average rate for each treatment size of the wells in Group III is shown in **Fig. 22**. **Fig. 23** is a cumulative probability plot of the 1-year, 2-year, 3-year, and 5-year cumulative gas production for each treatment size in Group III.

Fig. 24 is a graph of Best Year average rate versus the 3-year cumulative gas production for all wells in Group IV. Again, the wells have been color-coded by treatment size. Cumulative probability plots for the Best Year average rate and 3-year cumulative production for each treatment size in Group IV are shown in **Fig. 25** and **Fig. 26** respectively.

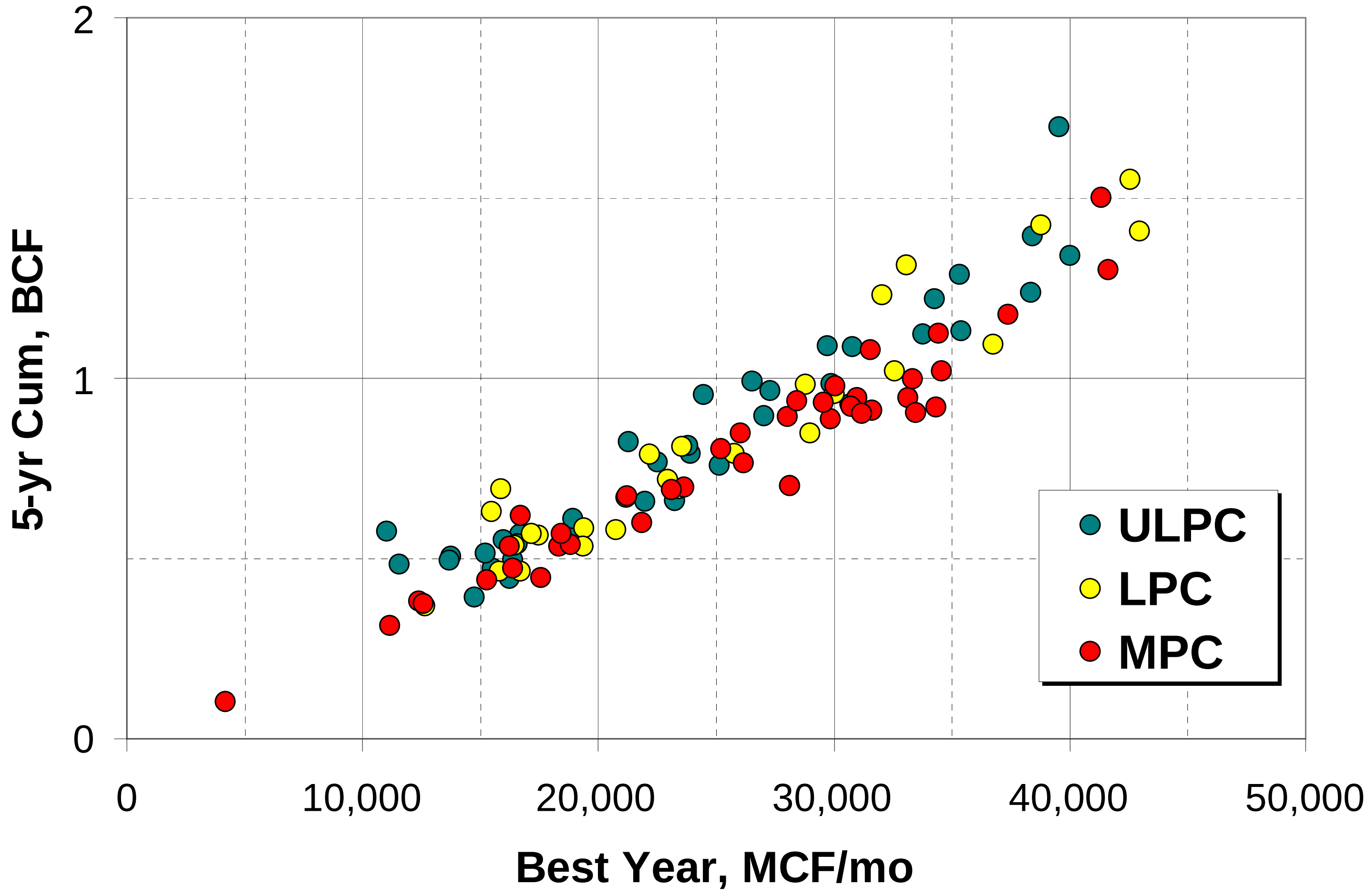


Fig. 21 – Correlations of Different Treatment Sizes of Best Year and Long-term Production for Wells in Group III

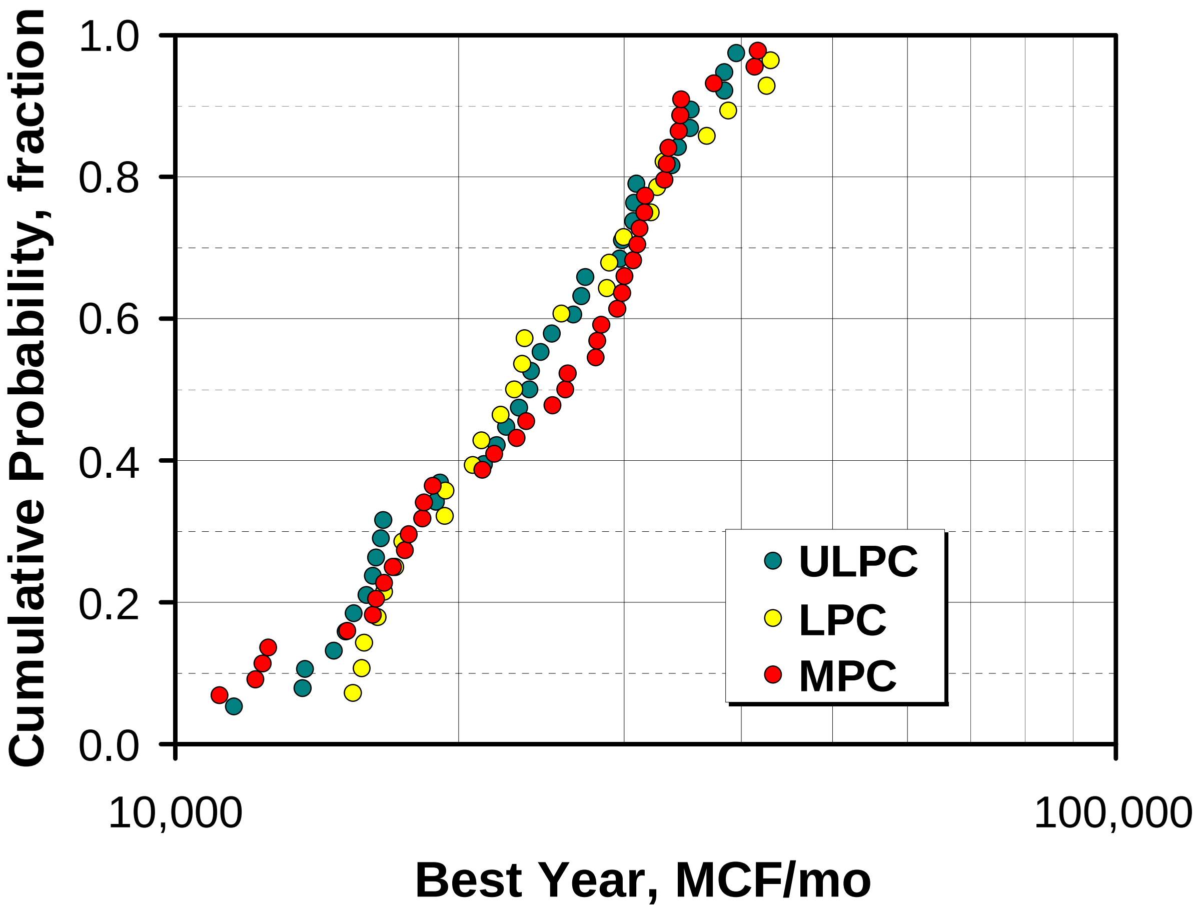


Fig. 22 – Probability Distribution of Best Year for Different Treatment Sizes in Group III

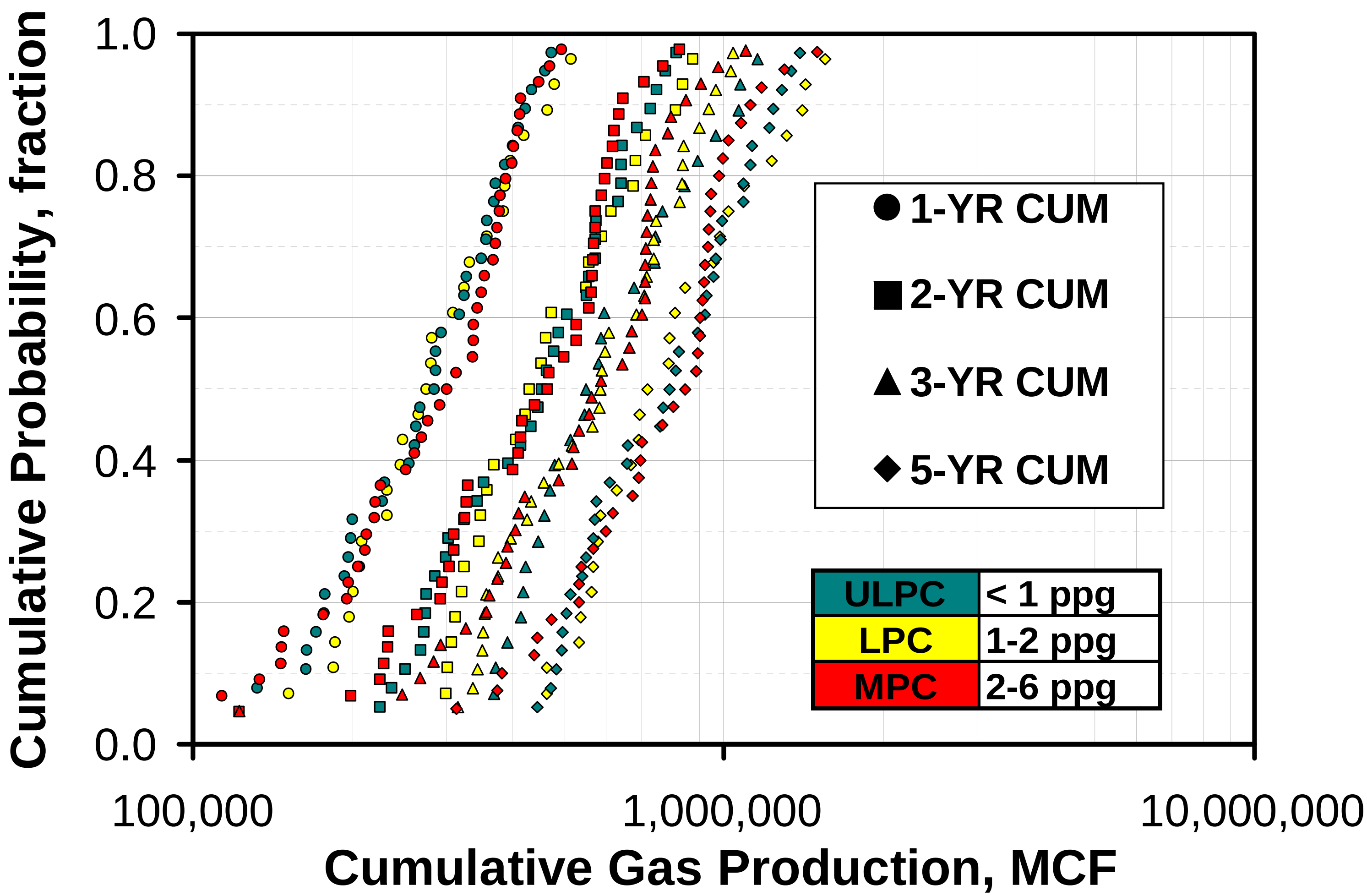


Fig. 23 – Probability Distribution of Long-term Production of Different Treatment Sizes for Wells in Group III

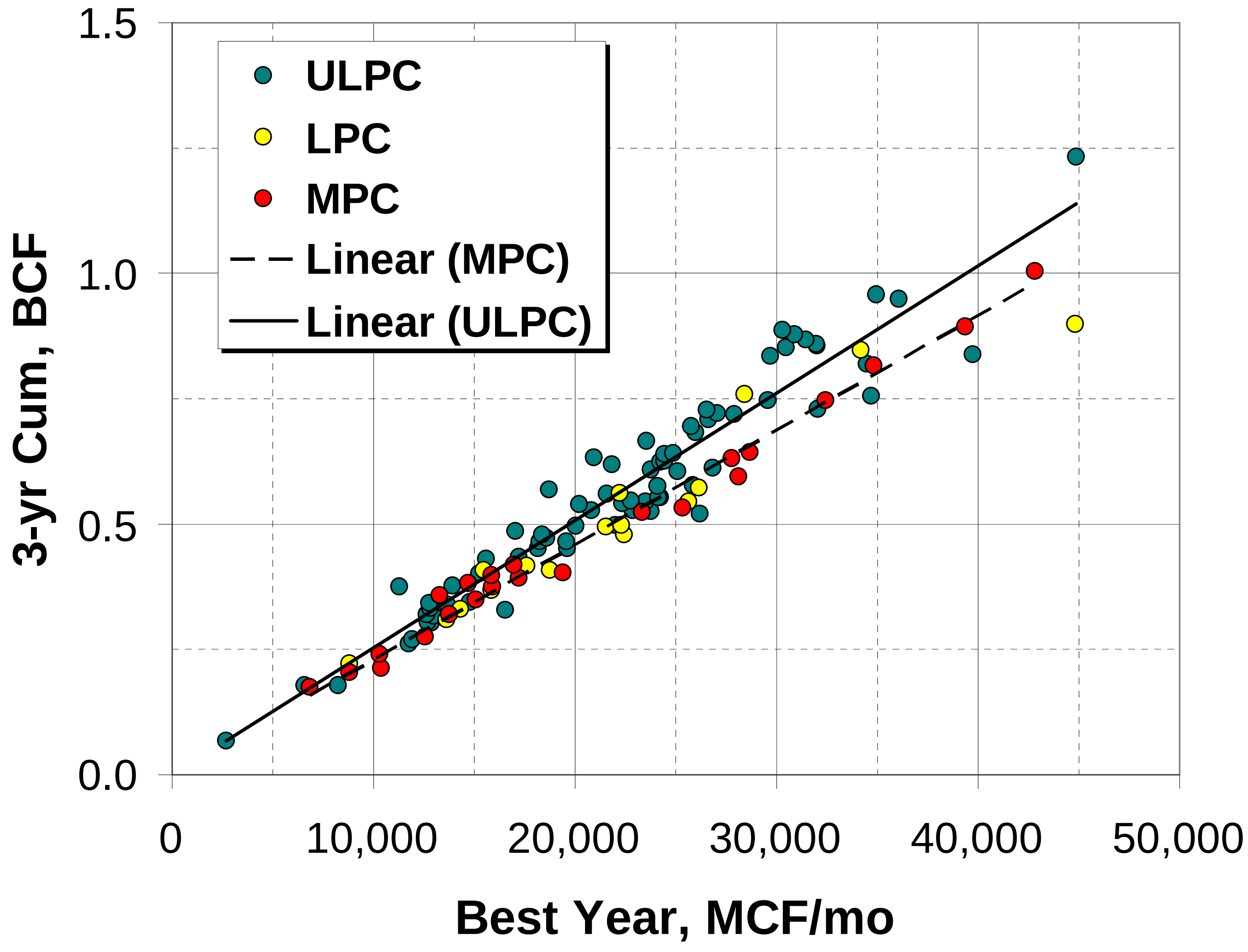


Fig. 24 - Correlations of Different Treatment Sizes of Best Year and Long-term Production for Wells in Group IV

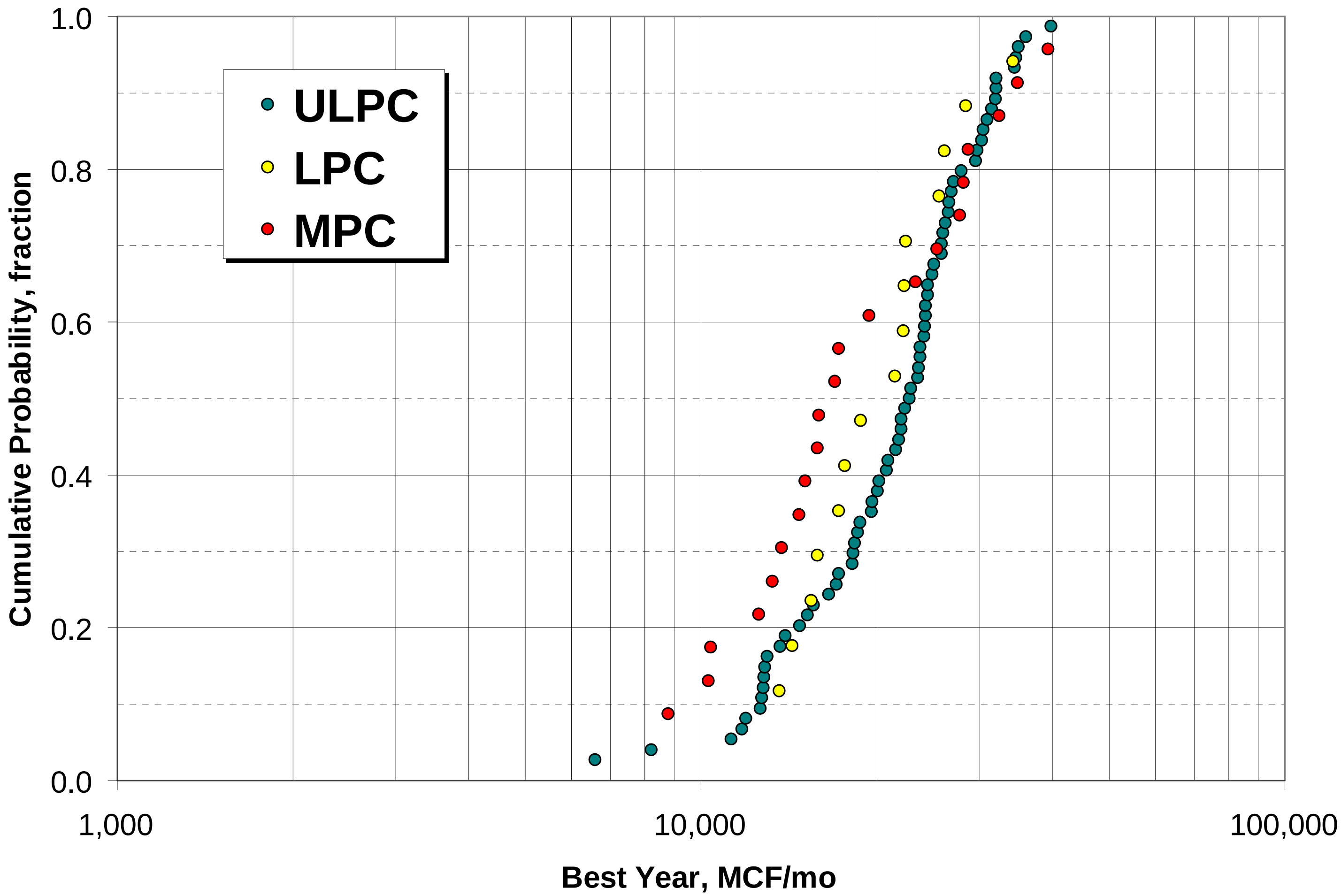


Fig. 25 – Probability Distribution of Best Year for Different Treatment Sizes in Group IV

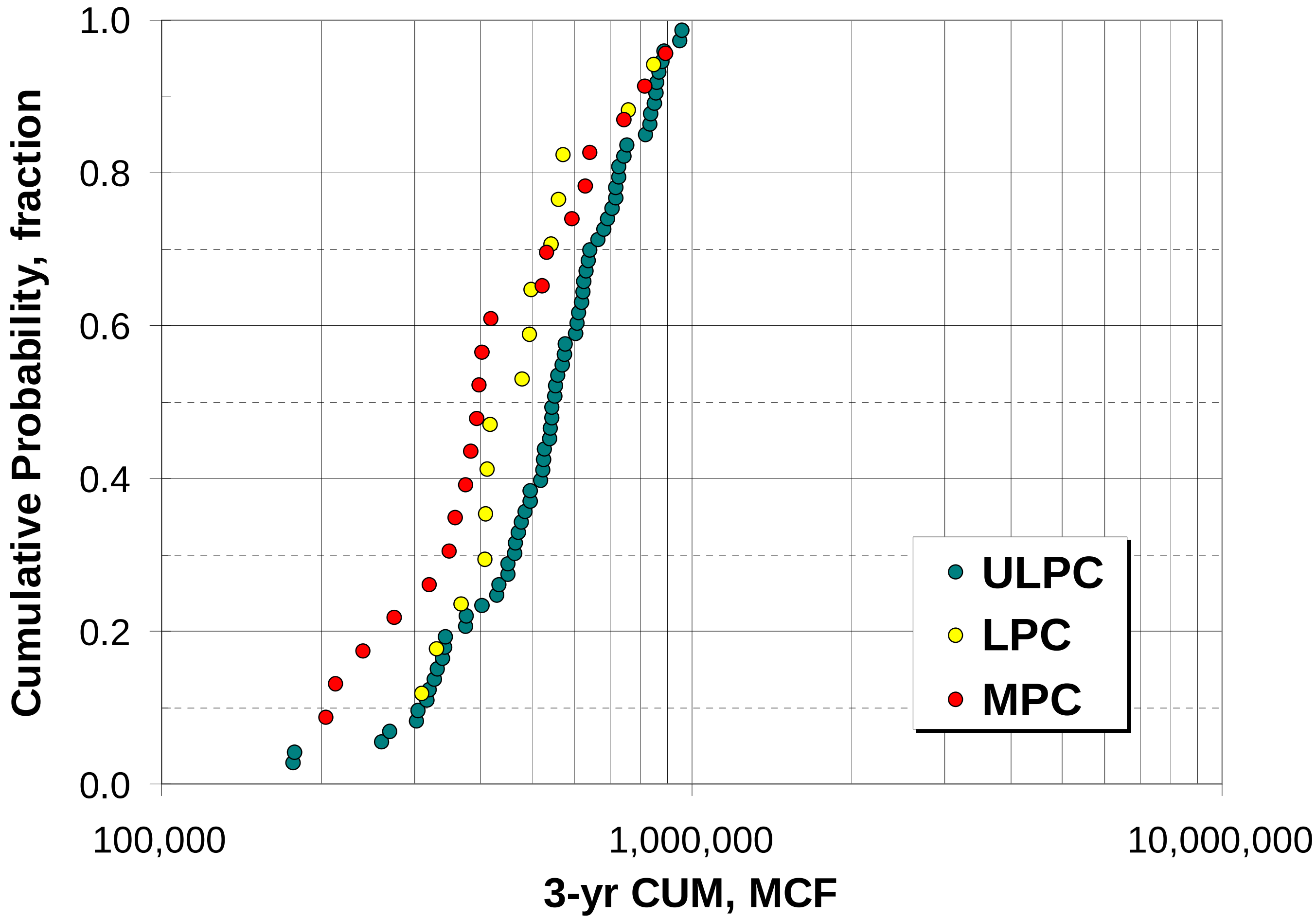


Fig. 26 – Probability Distribution of Long-term Production of Different Treatment Sizes for Wells in Group IV

Simulation Results

Because the analyses of the field data, especially the history match of the production data with a reservoir simulator to estimate values of permeability, fracture length, fracture conductivity and drainage area was so ambiguous and non-unique, we decided to generate a set of “theoretical data” for analysis. We used the data in Table 9, Table A-1, and Fig. A-1 to generate theoretical production data. The benefit of this approach is that we know the reservoir description. We can analyze the theoretical data to be certain our analysis methods are valid.

A graph of Best Year average rate versus 5-year cumulative gas production for all of the simulations is shown plotted alongside the actual Group III field values in **Fig. 27**. **Fig. 28** is the same type of graph as Fig. 27 only the simulated values that do not follow the general distribution of the actual field data have been eliminated. Fig. 28 has been refined further in **Fig. 29** by grouping the simulations by permeability and fracture length. **Fig. 30a-Fig. 30e** have been created to make the data in Fig. 29 easier to see by only presenting data for one fracture length at a time.

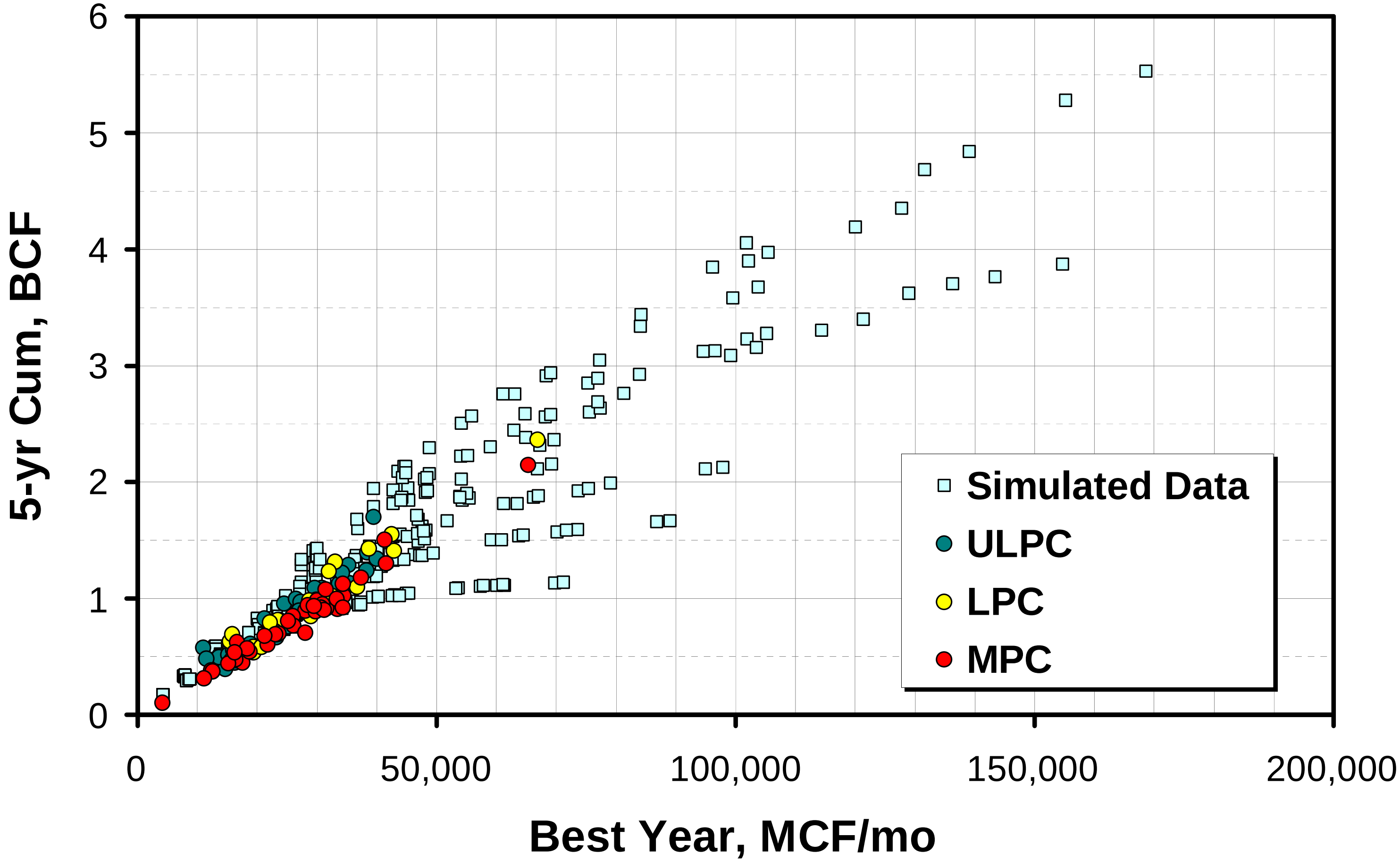


Fig. 27 – Simulated Well Production Data

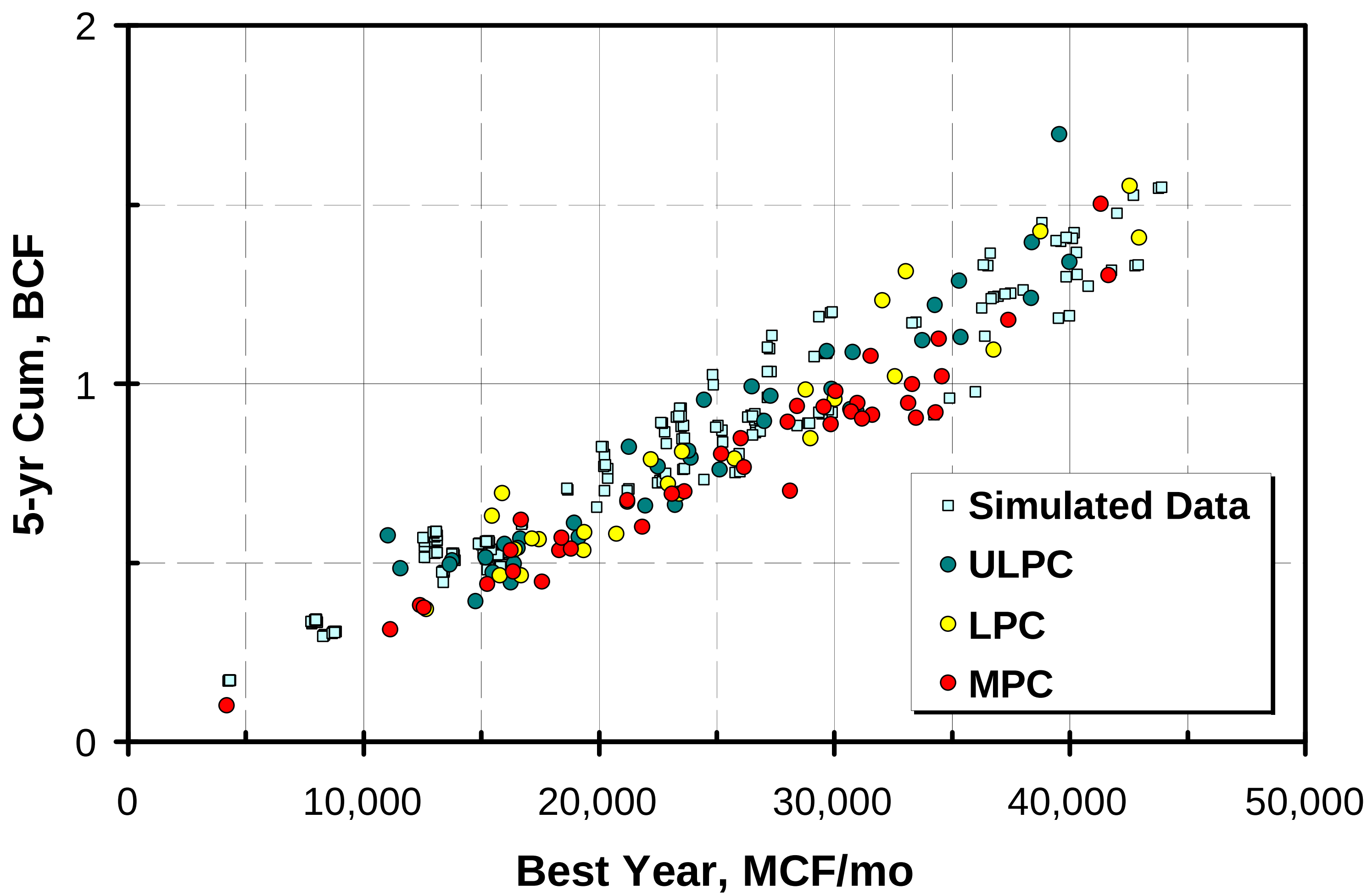


Fig. 28 – Simulated Production Data Matching the Overall Distribution of Group III

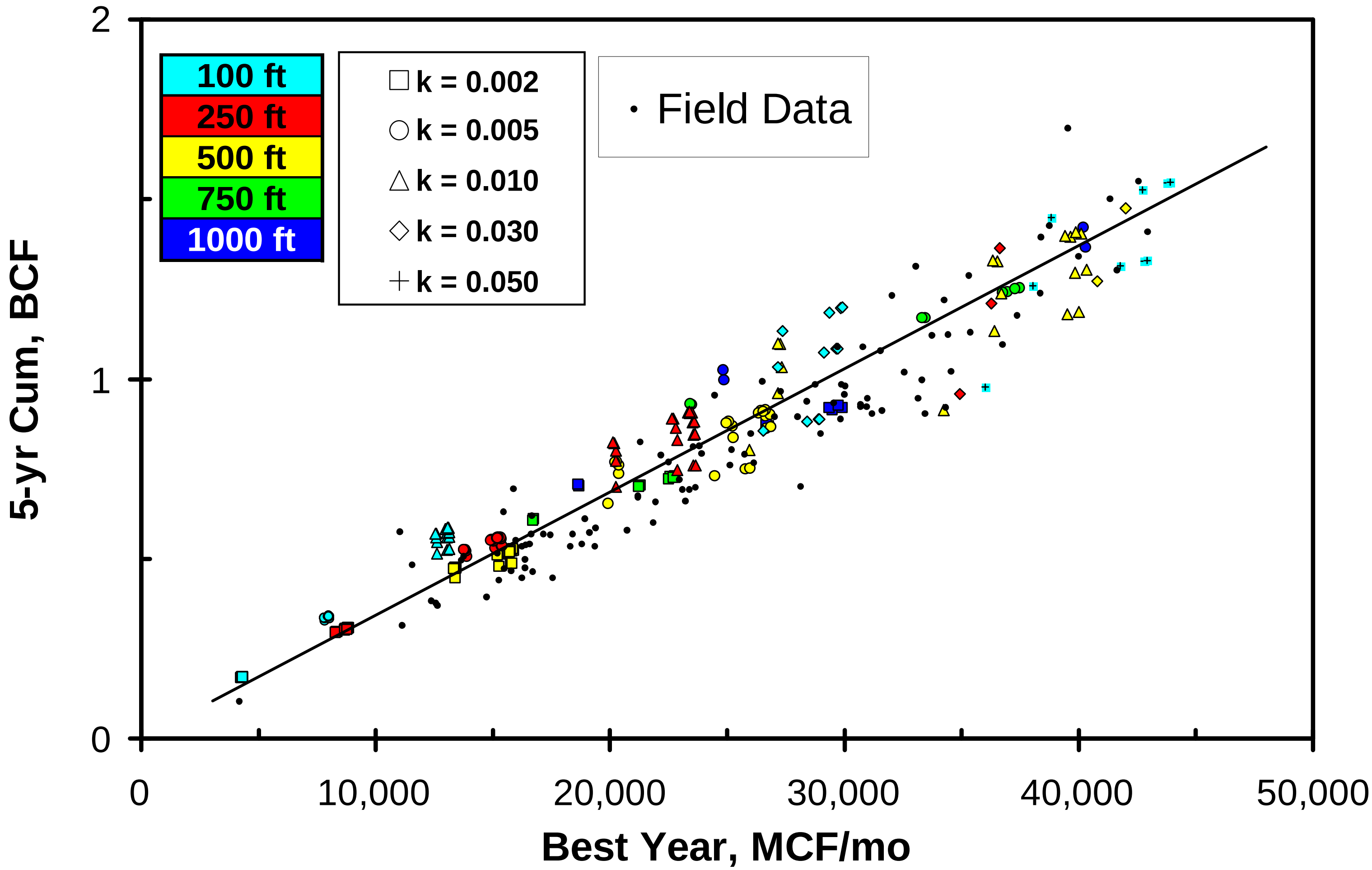


Fig. 29 – Simulated Production Data Grouped by Permeability and Fracture Length

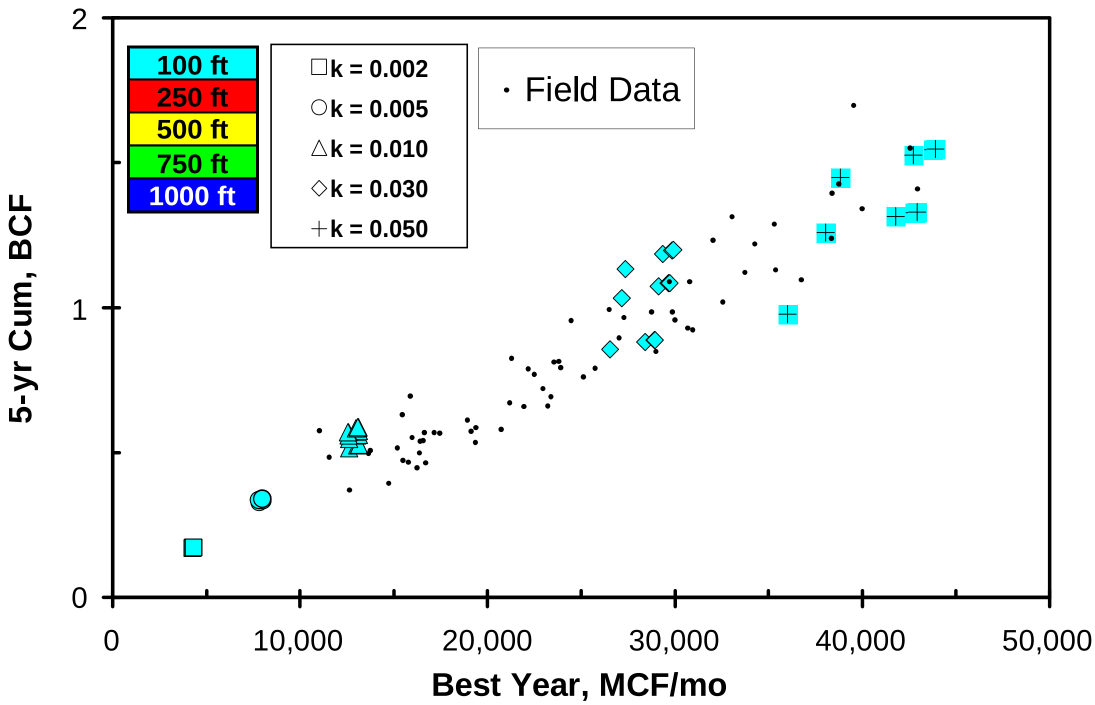


Fig. 30 – Simulated Data Grouped by Fracture Length
(a) 100 ft

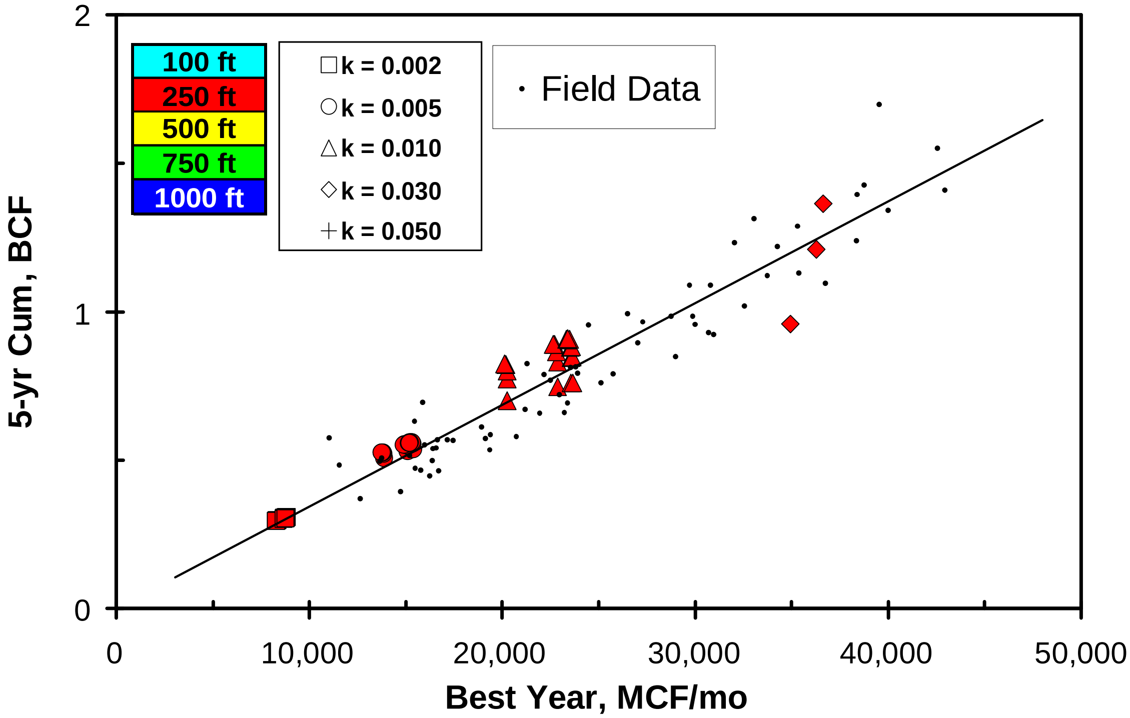


Fig. 30 Continued
(b) 250 ft

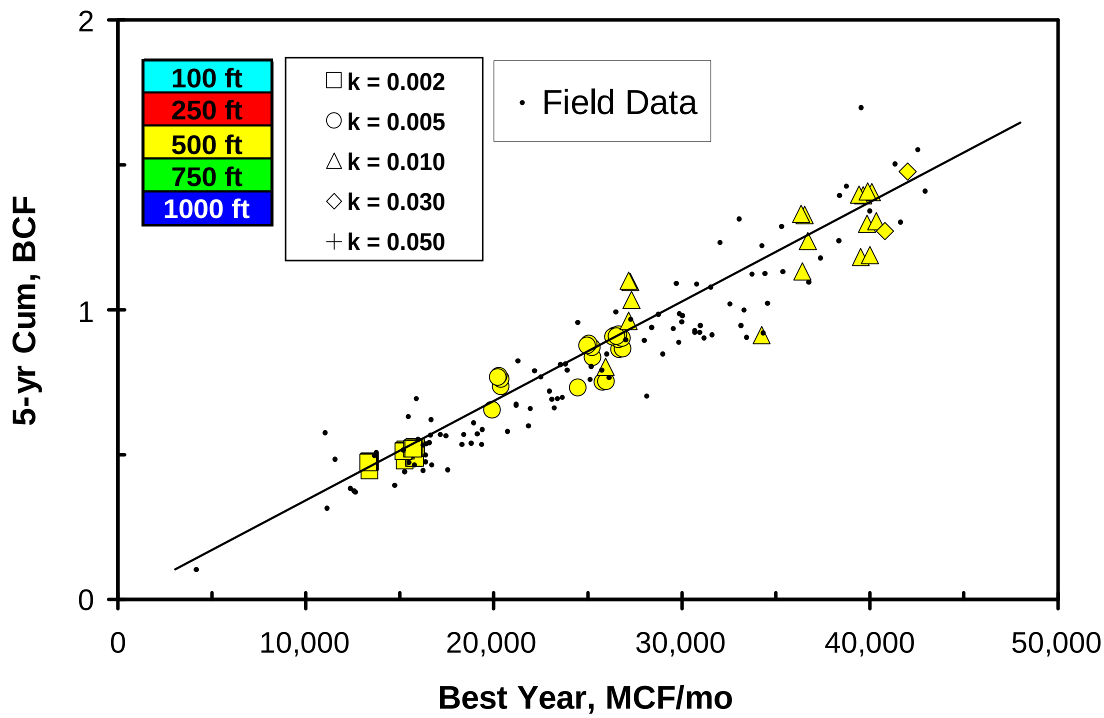


Fig. 30 Continued
(c) 500 ft

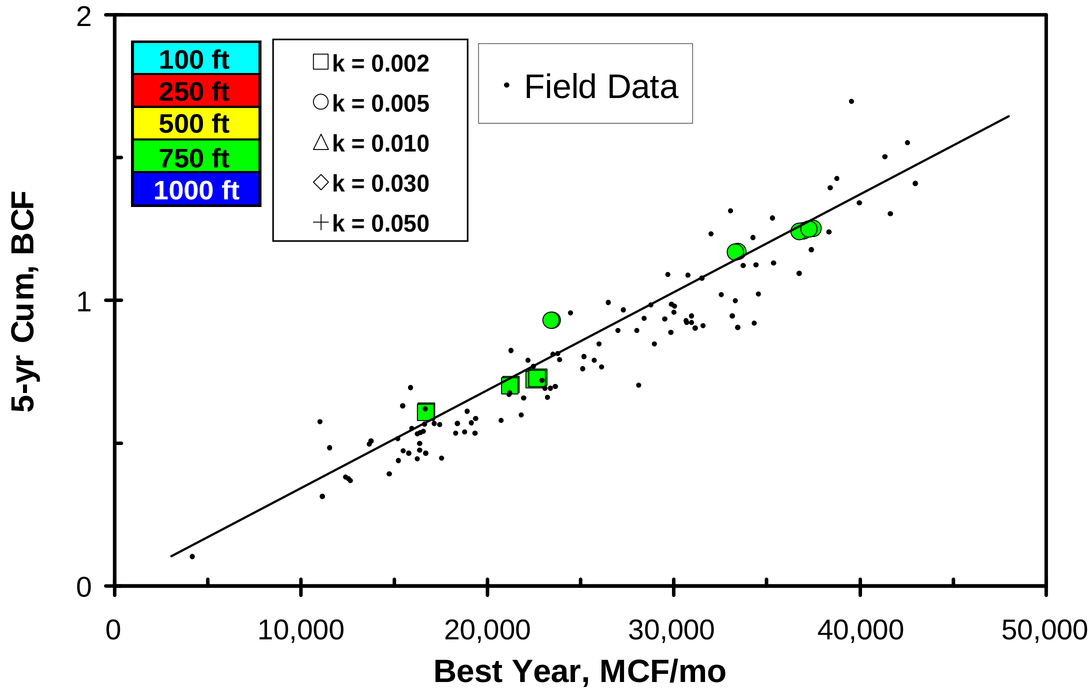


Fig. 30 Continued
(d) 750 ft

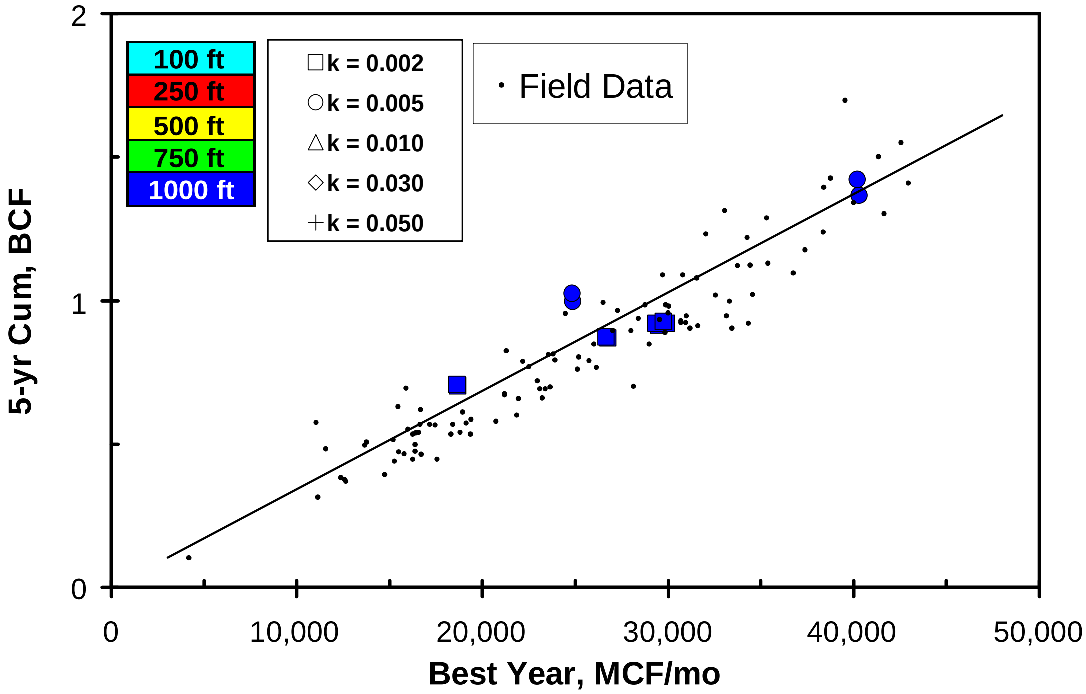


Fig. 30 Continued
(e) 1000 ft

Discussion of Results

Group III

The trend between Best Year average rate versus 5-year cumulative production shown in Fig. 21 appears to be relatively similar for all treatment sizes. Likewise, the cumulative probability plot for the Best Year average rate shown in Fig. 22 is also very similar for all treatment sizes. Cumulative probability graphs for the 1-year, 2-year, 3-year, and 5-year cumulative production shown in Fig. 23 appear to be very similar as well. From a statistical and probabilistic standpoint there appears to be little to no difference overall in the well performance of the different treatment sizes in Group III based on Fig. 21, Fig. 22, and Fig. 23.

Fig. 29 is a graph of the simulated Best Year average rates versus simulated 5-year cumulative gas production alongside the actual field data. The simulations have been grouped and identified by permeability and fracture length. If treatment size or type is taken to be synonymous with the resulting fracture length, given a specific treatment size, the distribution from low to high Best Year average rates and 5-year cumulative gas production is dominated by the permeability distribution. An example of this can be seen by observing the trend of the simulations where 500 ft was used as the fracture length. This can be seen more clearly in Fig. 30c where only data for 500 ft fracture length is shown.

These points are indicated with the color yellow in Fig. 30c. Notice that the low values for Best Year average rate and 5-year cumulative gas production correspond to a permeability of 0.002 md (indicated with the square symbol). Both the Best Year average rate and 5-year cumulative production increase with permeability as indicated with the changes in shape of the points on the plot.

Fig. 29 appears to indicate that many combinations of fracture length and permeability can result in similar values for Best Year average rate and 5-year cumulative production. However, taking the distribution of the simulations and the field data as a whole, some interesting observations can be made. Fig. 30a-Fig. 30e have been created to make the data in Fig. 29 easier to see by only presenting data for one fracture length at a time. As Fig. 30a-30e are interpreted it must be kept in mind that the reservoir quality distribution (identified in this case by permeability) is most likely log normally distributed. Assuming permeability is log normally distributed, it is interesting to note that simulation data generated with large fracture lengths only occur in the distribution of field data if the simulation was also generated with low permeability. Observing the permeability distribution of the simulated data for the 750 and 1000 ft fracture lengths in Fig. 30d and Fig. 30e it can be seen that only 0.002 and 0.005 md occur for these lengths. It is very unlikely that only the poor reservoir quality was stimulated and resulted in long fracture lengths. If 750 and 1000 ft fracture lengths are common then there should be a wider distribution of permeability associated with these simulations. The simulated data generated with 100 ft fracture lengths, shown in Fig. 30a, do not appear to fit the general distribution of field data either. The simulated data generated with 250 and 500 ft fracture lengths shown in Fig 30b and Fig. 30c appear to have the most logical permeability distribution while also fitting the general distribution of Best Year average rate and 5-year cumulative production. This can be investigated further by observing **Fig. 31**. Fig. 31 is a cumulative probability graph of the distribution of 5-year cumulative production for the simulated data grouped by fracture length. The probability plots were generated with the mean and standard deviation of the simulated data assuming a log normal distribution. Cumulative probability graphs of the 5-year cumulative production for the field data are shown on Fig. 31 as well. As can be seen in Fig. 31**,** the probability curves for 750 and 1000 ft fracture lengths do not appear to fit the distribution of the field data. The probability distributions for the 100 and 250 ft fracture lengths appear to under-predict the distribution of the field data. The probability distribution for the 500 ft fracture length appears to show very good agreement with the probability distribution of the field data.

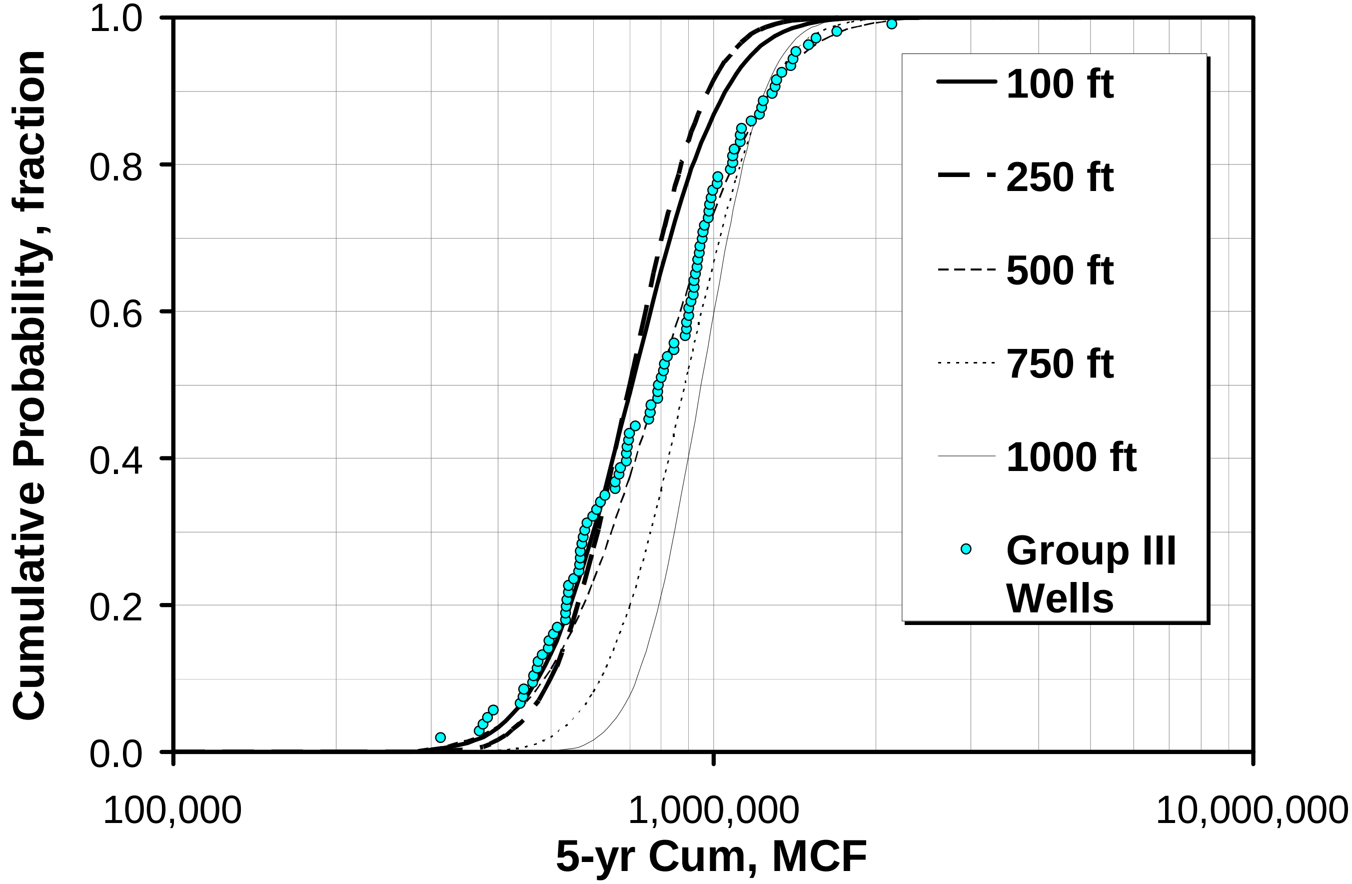


Fig. 31 – Theoretical Probability Distribution of Simulated Data

Group IV

As shown in Fig. 24, there appears to be significant difference between the Best Year average rate-cumulative production trends for the different treatment sizes in Group IV. First, the MPC treatments appear to have a greater frequency of low Best Year average rates and 3-year cumulative production when compared to the other treatment sizes. Second, the MPC treatments appear overall to have a smaller ratio for the Best Year average rate:3-year cumulative production when compared to the other treatment sizes. This indicates that for a given value of Best Year average rate the MPC treatments will most likely result in a lower 3-year cumulative production than the other treatments. Observing the cumulative probability plot for the Best Year average rate in Fig. 25, it can be seen that there is a clear distinction between the different treatment sizes. The MPC treatments have lower Best Year average rates overall. The ULPC treatments result in higher Best Year average rates overall. The cumulative probability plots for 3-year cumulative production shown in Fig. 26 indicate similar results. The MPC treatments result in significantly lower values for 3-year cumulative production when compared to the other treatments. The ULPC treatments result in the highest overall distribution of 3-year cumulative production. The ULPC probability curve is consistently about 100 MMcf larger than the MPC probability curve indicating that the ULPC treatments are typically producing 100 MMcf more gas than the MPC treatments.

Technical Implications

In both Group III and Group IV, the viscous gel treatments appear to have no significant advantage over the waterfrac treatments. Based what has been learned from the case histories, this may be a result of gel damage in the fracture and because at low bottomhole temperature the viscous gels are not cleaning up well. It is very likely that the fluids used in the larger treatments are not optimal for the conditions of the Cotton Valley. As the case histories have shown, larger, high proppant volume treatments can significantly improve well performance and overall recovery when the fracturing fluids are appropriate for reservoir conditions. Better fluids and or breaker systems need to be used and or developed for low temperature tight gas sand reservoirs such as the Cotton Valley that do not respond favorably to polymer-based fluids. If it is difficult to find or develop viscous fluids that will be compatible with reservoirs like the Cotton Valley, strong, light weight proppants may be used to allow fluids like water to effectively transport more proppant.

Economic Implications

The probability graphs shown in Figs. 22,23, 25, and 26 have important economic implications for the development strategy for reservoirs like the Cotton Valley. Fig. 22 and 23 indicate that the probability of obtaining a well with a given outcome is relatively the same regardless of the treatment one uses in Group III. Fig. 25 and 26 indicate that smaller treatments will result in better wells overall in Group IV. Waterfracs typically cost about half as much as large conventional treatments. Based on these plots it is more economic and less risky to use waterfracs. From an economic and development standpoint waterfracs are currently the best option in this reservoir. Operators can only justify using larger and or more expensive treatments if these treatments can effectively shift the overall probability curve of the large treatments such as in Fig. 23 significantly to the right. Until technology can do this cost-effectively, larger treatments in reservoirs like the Cotton Valley do not make economic sense. This reiterates the point that better fluids and or breaker systems and or strong, light weight proppants need to be developed for low temperature tight sand reservoirs like the Cotton Valley.

CONCLUSIONS AND RECOMMENDATIONS

On the basis of the case histories published in the literature we offer the following conclusions:

1. Case Histories show that large proppant volumes and viscous fluids are necessary to optimally stimulate tight sands.
2. Case Histories show that when large proppant volumes and viscous fluids are not successful, it is typically because the fluids have not been optimal for conditions.
3. Case Histories suggest that poor performance of large conventional treatments in the Cotton Valley could be linked to gel damage in the fracture and using fluids not optimal for Cotton Valley conditions.

On the basis of the analyses of data in the Carthage field we offer the following conclusions:

1. For the data analyzed in this study, large proppant volume and viscous fluid treatments appear to show no significant advantage over low viscosity, low proppant volume treatments in the Cotton Valley sands of the Carthage field.

2. Waterfracs will be a better treatment option than large conventional treatments for stimulating the Cotton Valley in Carthage field from an economic and development standpoint until better, cost effective fluids can be used to make large treatments successful.

On the basis of both the case histories and the data analyses for the Carthage field we offer the following recommendations:

1. The industry needs to find ways to effectively place high proppant volumes into the fracture without damaging the fracture or the formation near the fracture when the reservoir temperature is less than 275°F.
2. The industry needs to better understand how to select the appropriate fluids and proppants on the basis of the environment and application for which they will be used.
3. The industry needs to develop strong light-weight proppants, better fluids, and better breaker systems for low temperature reservoirs (225-275°F) like the Cotton Valley sands that appear to respond unfavorably to the currently available polymer-based fracturing fluids.
4. Hybrid fracture treatments may be the best option for stimulating low temperature tight gas sands (225-275°F) until better fluids are developed that will break clean.

NOMENCLATURE

k	= permeability
kh	= permeability-thickness product
Φh	= porosity-thickness product
OGIP	= Original Gas-in-place
L_f	= Fracture Half-length
w-k_f	= Fracture Conductivity
P_i	= Initial Reservoir Pressure
DOFP	= Day of First Production
ULPC	= Ultra-low Proppant Concentration
LPC	= Low Proppant Concentration
MPC	= Medium Proppant Concentration
HPC	= High Proppant Concentration

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APPENDIX

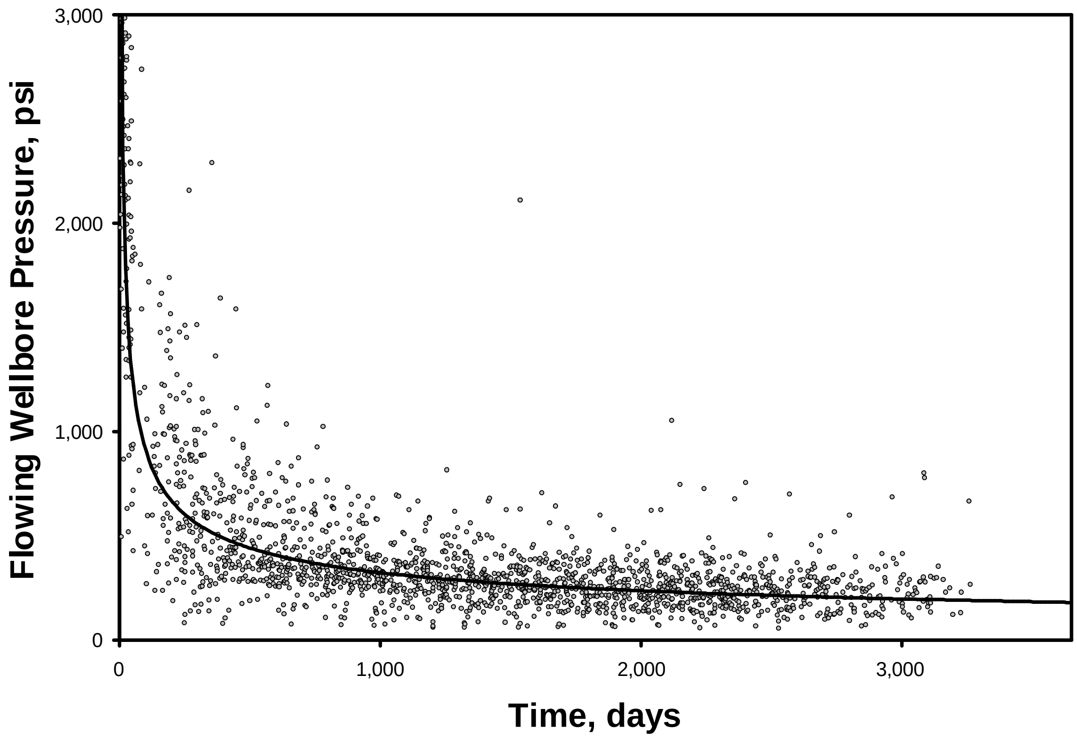

Fig. A-1 – General Flowing Wellbore Pressure Trend of a Well in Group III

Table A-1 – Analytical Simulator Inputs

Description	Value	Units
Gas Gravity	0.67	None
Net Pay	140	ft
Effective Porosity	0.11	fraction
Water Saturation	0.37	fraction
Initial Pressure	2,964	psi

VITA

NAME:	Nicholas Ray Tschirhart
BORN:	Houston, Texas
PERMANENT ADDRESS:	Harold Vance Department of Petroleum Engineering 3116 TAMU College Station, TX 77841
EDUCATION:	B.S. Mechanical Engineering, Texas A&M University M.S. Petroleum Engineering, Texas A&M University
MEMBER:	Society of Petroleum Engineers