Stimulation Technologies for Deep Well Completions

DE-FC26-02NT41663

Technical Progress Report No. 3

10/01/03 – 03/31/04

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Morgantown, WV**

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Abstract

The Department of Energy (DOE) is sponsoring the Deep Trek Program targeted at improving the economics of drilling and completing deep gas wells. Under the DOE program, Pinnacle Technologies is conducting a study to evaluate the stimulation of deep wells. The objective of the project is to assess U.S. deep well drilling and stimulation activity, review rock mechanics and fracture growth in deep, high-pressure/temperature wells and evaluate stimulation technology in several key deep plays. An assessment of historical deep gas well drilling activity and forecast of future trends was completed during the first six months of the project; this segment of the project was covered in Technical Progress Report No. 1. During the next six months, efforts were primarily split between summarizing rock mechanics and fracture growth in deep reservoirs and contacting operators about case studies of deep gas well stimulation as documented in Technical Progress Report No. 2. This report details work done with Anadarko and ChevronTexaco in the Table Rock Field in Wyoming.

Table of Contents

Abstract	i
Table of Contents.....	iii
List of Figures	v
List of Tables.....	vii
1. Summary	1
1.1 State-of-the-Art Technology in Deep Formation Stimulation.....	1
1.2 Review/Summary of Rock Mechanics and Fracture Growth in Deep Reservoirs	1
1.3 Fracture Modeling, Production Data Analysis, Reservoir Modeling, and Case Histories	1
2. Conclusions.....	5
3. Discussion	7
3.1 Introduction	7
3.2 Fracture Engineering	11
3.2.1. Table Rock #123 Upper Weber Frac Attempt.....	14
3.2.2. Table Rock #124 Lower Weber and Dolomite.....	17
3.2.3. Table Rock #124 Upper Weber.....	20
3.2.4. Table Rock #125 Upper Weber.....	24
3.2.5. Higgins #19 Lower Weber	26
3.2.6. Higgins #19 Upper Weber.....	30
3.2.7. Higgins #17 Dolomite	34
3.2.8. Post-Frac PBU in Table Rock #124 Lower Weber and Dolomite	41

List of Figures

Figure 1. Example showing typical log section: Higgins # 19	9
Figure 2. Table rock field structure map	10
Figure 3. Typical fracture treatment data for conventional CO ₂ frac: Table Rock 124 Upper Weber	11
Figure 4. Illustration of fracture complexity: Near-wellbore versus far-field.....	13
Figure 5. Example of pressure-dependent leakoff due to fissure opening: Table Rock 124 Lower frac...	14
Figure 6. Treatment data: Table Rock 123 Upper Weber frac attempt.....	15
Figure 7. Fracture closure analysis: Table Rock 123 Upper Weber	15
Figure 8. Estimating tortuosity and perforation friction: Table Rock 123 Upper Weber	16
Figure 9. Net pressure match: Table Rock 123 Upper Weber Frac attempt	16
Figure 10. Model fracture geometry: Table Rock 123 Upper Weber Frac attempt	17
Figure 11. Treatment data: TR 124 Lower Weber and Dolomite	18
Figure 12. Fracture closure analysis: TR 124 Lower Weber and Dolomite	18
Figure 13. Estimating tortuosity and perforation friction: Table Rock 124 Lower Weber and Dolomite.....	19
Figure 14. Net pressure match: Table Rock 124 Lower Weber and Dolomite	19
Figure 15. Fracture geometry: Table Rock 124 Lower Weber and Dolomite	20
Figure 16. Treatment data: Table Rock 124 Upper Weber.....	21
Figure 17. Fracture closure analysis: Table Rock 124 Upper Weber	21
Figure 18. Net pressure match: Table Rock 124 Upper Weber	22
Figure 19. Model fracture geometry: Table Rock 124 Upper Weber	22
Figure 20. RA tracer log in Table Rock #124.....	23
Figure 21. Treatment data: TR 125 Upper Weber	24
Figure 22. Fracture closure analysis: TR 125 Upper Weber.....	25
Figure 23. Net pressure match: TR 125 Upper Weber.....	25
Figure 24. Model fracture geometry: TR 125 Upper Weber	26
Figure 25. Treatment data mini-frac: Higgins 19 Lower Weber frac attempt	27
Figure 26. Fracture closure analysis: Higgins 19 Lower Weber frac attempt.....	27
Figure 27. Treatment data: Higgins 19 Lower Weber frac attempt	28
Figure 28. Net pressure match: Higgins 19 Lower Weber frac attempt	29
Figure 29. Model fracture geometry: Higgins 19 Lower Weber frac attempt	29
Figure 30. Treatment data: Higgins 19 Upper Weber frac.....	31
Figure 31. Fracture closure analysis: Higgins 19 Upper Weber frac	31
Figure 32. Net pressure match: Higgins 19 Upper Weber frac.....	32
Figure 33. Model fracture geometry: Higgins 19 Upper Weber frac	32
Figure 34. RA tracer log in Higgins #19.....	33
Figure 35. RA tracer log in Higgins #17.....	35
Figure 36. Treatment data: Higgins 17 acid fracture	36
Figure 37. Net pressure match of Higgins 17 acid fracture treatment data.....	37

Figure 38. Model fracture geometry for Higgins 17	38
Figure 39. Acid etched fracture conductivity and length for Higgins 17	38
Figure 40. One-year gas production and NPV Forecast	39
Figure 41. Acid etched fracture conductivity and length predicted by the ADP model	40
Figure 42. Production comparison based on the FracproPT default and ADP acid models	40
Figure 43. Production comparison with permeability values of 0.5, 1.0 and 5.0 mD.....	41
Figure 44. Post-frac PBU analysis in Table Rock #124.....	42

List of Tables

Table 1. Summary of Fracture Treatments: Diagnostic Injections 12

Table 2. Summary of Fracture Treatments: Propped and Acid Frac Treatment 12

Table 3. Summary of Fracture Treatments: Comments 12

Table 4. Summary of Fracture Analysis Results..... 13

Table 5. Post-Frac Analysis Results Table Rock #124 42

1. Summary

Pinnacle Technologies (Pinnacle) is performing a study on stimulation for deep well completions as part of the Department of Energy's (DOE) Deep Trek Program. The Department of Energy's (DOE) Deep Trek Program is targeted to improving the economics of drilling and completing deep wells. This project is focused on the second objective of the Deep Trek program, "Improved Economics in Deep Well Completions." The objective of the project is to review current and past stimulation activity and research results for deep well completions and develop information for the industry that will help reduce uncertainty and increase success in frontier and emerging deep formation plays.

The Pinnacle study is focused on three major objectives:

1. Evaluate the current state-of-the-art technology in stimulation for deep formations through industry interviews and a comprehensive literature review and assessment
2. Evaluate rock mechanics issues and fracture growth behavior in deep formation completions through literature review, interviews and rock mechanics analysis
3. Perform three to five small case studies evaluating stimulation in key deep formations

This report covers the second six months of the study during which effort was split between wrap up of the first objective and starting efforts on the second and third objectives

1.1 State-of-the-Art Technology in Deep Formation Stimulation

Task 1 consists of a comprehensive review of current literature on stimulation technology for deep formations and interviews with operators, service companies and consultants. The result will be documentation of stimulation and completion practices in major deep formations and the identification of operator and service company technical requirements. Results of this work were documented in previous reports.

1.2 Review/Summary of Rock Mechanics and Fracture Growth in Deep Reservoirs

Task 2 consists of an evaluation of the rock mechanics issues and fracture growth behavior in deep formations. Results of this work were documented in previous reports.

1.3 Fracture Modeling, Production Data Analysis, Reservoir Modeling, and Case Histories

Task 3 consists of an evaluation of stimulation in three to five deep gas formations identified in Task 1. The focus of the evaluations will be the integration of fracture modeling and production data analyses to better understand fracture performance. Based on the activity levels forecast in Task 1 and resource potential in each region, NETL has selected key regions for consideration for further study. For each major deep gas region, five to ten of the most active operators were contacted about participating in a study. Case study partners were identified for three areas:

- ConocoPhillips – Jennings Ranch Field in South Texas
- Anadarko and ChevronTexaco – Table Rock Field in Wyoming

- Marathon – Several wells in Oklahoma

This report covers work performed with Anadarko and ChevronTexaco. This study focused on three deep gas productive targets in the Table Rock Field in Wyoming. The primary target is a higher permeability Dolomite layer (20 to 30 ft thick) surrounded by thick (150 ft to 200 ft) low permeability/porosity sandstones (secondary targets) designated as the Lower Weber (below Dolomite), and Upper Weber (above Dolomite) at depths of roughly 17,300 to 18,100 feet. While the Dolomite provides the majority of the gas flow rate (75% to 90% of total without hydraulic fracturing), it is limited in reserves due to its smaller thickness. The Weber sands, on the other hand, are very thick and potentially contain vast amounts of gas reserves but are limited in flow rate and require hydraulic fracture stimulation. Natural fractures are believed to play a role in the production of both Weber sands and Dolomite. One theory is that the Dolomite could actually be serving as a high permeability conduit, with the Weber sands feeding gas through a natural fracture system. Decline curve estimates and gas-in-place calculations indicate that gas reserves are higher than can be attributed to the Dolomite alone; however, the current reserve estimates are very uncertain, having a large spread, which is partly due to uncertain delineation of the field and location of a water-contact. Studies are currently being performed to ascertain the reserve base.

The field includes 17 wells drilled in the late 70s and early 80s. All wells are located to the east of a NNE to SSW trending thrust fault. Recently ChevronTexaco and Anadarko have started a new wave of development in this field. Most of the older wells had natural completions in the Dolomite (perforated and acidized) and, in some cases, the Upper Weber. Five of the older wells had hydraulic fracture completions with varying success. Currently the Upper Weber and sometimes the Lower Weber are stimulated with hydraulic fractures followed by a natural completion in the Dolomite (perforate and acidize). The best well in the field was perforated and acidized only, and has a current cumulative production of about 34 BCF in twelve years. Well performances indicate that reservoir quality can vary significantly across the field, with the challenge being to obtain consistent economic success for every well drilled. Being able to exploit the large Weber gas reserves with effective hydraulic fracture stimulation would be an important “add-on” to the high productivity Dolomite.

The general problem with treatments in this area appears to be the creation of complex, multiple fracture systems during hydraulic fracturing. This causes fracture widths to be very small, which is problematic for pumping higher concentrations of proppant and has led to screenouts in the majority of treatments. The propagation of complex fractures and the inability to transport proppant deep into the hydraulic fracture will result in low quality fracture stimulation due to short, low conductivity fractures, which is aggravated by the high stress environment at large depths. This conclusion was supported by a post-frac pressure buildup test, which revealed largely ineffective fracture stimulation. The fracture complexity may also be related to the close proximity of a thrust fault, which can create complex stress fields. In addition, the normal- to even under-pressured pore pressure poses a severe challenge for effective hydraulic fracture stimulation and production.

Three different types of fracture treatments were reviewed in this study. The most frequently pumped design is a CO₂-assisted heavy crosslinked gel treatment with moderate concentrations of bauxite (up to 4 ppg). In January of 2004, one well was completed with a hybrid frac design, which uses a large slickwater pad followed by a “low gel loading” crosslinked fluid and lower proppant concentrations of bauxite (up to 2 ppg). The hope was that the hybrid design would increase fracture length, which is the most important design parameter in low permeability rock, while also reducing potential polymer damage to the natural fractures. In April 2004, an acid fracture treatment was pumped to target the Dolomite reservoir formation.

It is unclear at this point which type of treatment provides the best fracture stimulation. Fracture modeling indicates that the hybrid treatment may have created longer fractures but production was not better than in

the other conventional Upper Weber completions. The key to economic development of this field is to high-grade the selection of drilling locations to ensure a high quality Dolomite zone. Completion technology and stimulation of the low permeability Weber sands provides added value in these wells. The completion and stimulation of these wells are challenging and it appears that every attempt of improved stimulation does not result in a significant enhancement of well production as reservoir quality is the key driver for performance. It is highly recommended to more frequently employ diagnostic technologies such as pressure buildup tests to segregate completion effectiveness from reservoir quality and estimate pore pressure as this will help both in the optimization of well completion and reserves quantification.

2. Conclusions

1. There is strong evidence that created hydraulic fractures are very complex multiple fracture systems. The fracture complexity causes created fracture widths to be very small, which is problematic for pumping higher concentrations of proppant. The majority of treatments in this study had problems with severe increases of treating pressures during the proppant stages leading to screenouts in some cases. The fracture complexity may also be related to the close proximity of a thrust fault, which can create complex stress fields.
2. The propagation of a complex fracture system and the inability to transport proppant deeply into the fractures will result in low quality fracture stimulation due to short, low conductivity fractures. The post-frac pressure buildup in the Table Rock #124 (Lower Weber and Dolomite) supports this conclusion as it revealed largely ineffective fracture stimulation along with a permeability of about 0.63 md and formation flow capacity of 19 md-ft (mainly from Dolomite).
3. Fracture complexity was modeled both as multiple branches and increasing leakoff due to opening of natural fissures as injection pressures rise above initiation pressures of oblique oriented natural fractures. The hydraulic fracturing process at this point may actually be a mixed mode of shear and tensile fracturing. The opening of natural fissures is confirmed by pressure-dependent leakoff during the mini-frac falloffs. In addition, radioactive tracer logs also indicate separate fractures at each set of perforations.
4. There is no evidence that any of the Weber fracture treatments (except for the TR 124 where the Dolomite was intentionally perforated with the Lower Weber) physically fractured into the Dolomite; however, it is unclear at this point if the Weber sands will eventually feed into the Dolomite through natural fractures as the Dolomite is depleted.
5. Three different types of fracture treatments were performed:
 - 25% CO₂-assisted 50 to 60 lb/Mgal low-pH crosslinked gel with 30/50 bauxite and a 20/40 bauxite tail-in
 - Hybrid job with a large slickwater pad followed by a crosslinked 32 lb/Mgal gel and lower proppant concentrations of 0.25 ppg to 2 ppg 30/60 bauxite and 20/40 bauxite
 - Acid fracturing using a pad (linear or crosslinked gel) followed by 15% HCl gelled acid

It is unclear at this point which type of treatment provides the best fracture stimulation as only one hybrid treatment was successfully placed so far and initial flowback data indicators are uncertain due to reservoir quality issues; however, the successful hybrid treatment provided a production response that was on the lower end of comparable Upper Weber completions, showing that the desired goal of achieving a clearly better stimulation and flow response was not achieved. The other hybrid fracture attempt was unsuccessful as very high treating pressures precluded any type of propped stimulation. From a treating pressure perspective, it appears that the hybrid fracture was able to avoid proppant transport related pressure increases and place larger amounts of fluid and proppant. Modeling also indicated that a longer fracture was created, which could be a key issue in very low permeability rock.

6. In the study wells, the majority of the production is coming from the permeable Dolomite, with some limited contribution (0.8 MMCFD to 2.0 MMCFD) from the Weber sands. In one case (TR# 125), perforating and acidizing the Dolomite lifted production from about 1.5 MMCFD to 17 MMCFD. It is common procedure to complete the Dolomite after the Upper Weber has been fractured (exception is TR #124, where Dolomite was fractured with Lower Weber). The high gas flow rates from the Dolomite will serve as a natural gas lift for the continued frac water cleanup from the Weber sands.
7. The most important issue in developing this field is to identify well locations that will ensure a high quality Dolomite zone as this is the key to economic well production. The completion and stimulation of these wells are challenging and it appears that every attempt at improved stimulation does not result in a significant enhancement of well production as reservoir quality is the key driver for performance.
8. The goal to stimulate the Dolomite pay zone in the Higgins 17 was achieved, though the near-wellbore conductivity could have been improved by a Closed Fracture Acidizing (CFA) stage.
9. The short-term production forecast in the Higgins 17 is consistent with actual post-treatment production data of 2 MMscfd. The reservoir permeability has dramatic impacts on gas production, and the Dolomite zone seems to have a permeability of 0.5 mD based on early post-treatment production match.
10. Significant fracture upward growth in the Higgins 17 was observed and caused by a poor cement job in the upper intervals. The reservoir pressure was lower than expected as the wellbore was only filled with one-third of the completion fluid prior to the acid fracture treatment.
11. It is highly recommended to more frequently employ diagnostic technologies, such as pressure buildup tests, to segregate completion effectiveness from reservoir quality and estimate pore pressure, as this will help both in the optimization of well completion and reserves quantification.
12. The study did not evaluate reservoir characterization and well location strategies but understanding reservoir quality, especially natural fracturing, is important in this field.
13. Hydraulic fracture mapping to would assist in optimizing treatments in this field.
 - How does fracture azimuth vary with proximity to the thrust fault?
 - What complexities are evident with fracture mapping and how do they relate to screenout problems?
 - What is the overall fracture height growth and how effective is payzone coverage using various treatment types?
 - What is the created fracture length and how does it compare to estimates for effective fracture length from production?

3. Discussion

3.1 Introduction

This study focused on three deep gas productive targets in the Table Rock Field. The primary target is a higher permeability Dolomite layer (20 ft thick) surrounded by low permeability sandstones (secondary targets) designated as the Lower Weber (below Dolomite), and Upper Weber (above Dolomite) at depths of roughly 17,300 to 18,100 feet (**Figure 1**). A field structure map is shown in **Figure 2**. The most significant feature is a NNE to SSW trending thrust fault. All wells are located on the east side of this fault. Some of the issues outlined in this study such as hydraulic fracture complexity could be associated with a complex stress field created by the thrust fault.

The history of the field includes about 17 wells drilled in the late 70s and early 80s. Recently ChevronTexaco and Anadarko have started a new wave of development in this field. Most of the older wells had natural completions (perforated and acidized) in the Dolomite and, in some cases, the Upper Weber. Five wells had hydraulic fracture completions with varying success. The best well in the field was perforated and acidized only and has a current cumulative production of about 34 BCF. Well performances indicate that reservoir quality can vary significantly across the field with the challenge being to obtain consistent economic success for every well drilled.

Both the Lower Weber and Upper Weber section are gas-filled low porosity sandstones (3%) with limited amounts of natural fractures. The Upper Weber section is generally considered to be higher reservoir quality than the Lower Weber. It is uncertain at this point how the two sandstone sections interact with the higher permeability, higher porosity Dolomite. One theory is that the Dolomite is connected by natural fractures to the neighboring sandstones and serves as a “conduit” for additional drainage and reserves from these fairly thick sections. RFTs generally indicate that pore pressures are currently below hydrostatic pressure, in the range of 5,000 psi to 6,000 psi at about 17,500 ft (0.29 to 0.34 psi/ft). These conditions pose quite a challenge for hydraulic fracturing given the 18,000-ft well depth and fracture treating pressures.

The main type of fracture design used for most wells includes pumping 25% CO₂-assisted 50 to 60 lb/Mgal low-pH crosslinked gel with 30/50 sintered bauxite and a 20/40 sintered bauxite tail-in at the end of the treatment. Bottomhole slurry rates are about 30 bpm and proppant ramps are generally 1 ppg to 4 ppg with about 150 klb of total proppant and 3,500 bbl of total slurry volume. A small proppant slug of 30/60 proppant (0.25 ppg) is usually pumped during the pad. Pad sizes are about 50%. Most treatments showed significant increases of treating pressures after 1 ppg proppant concentrations entered the hydraulic fracture, with some treatments resulting in premature screenouts (**Figure 3**).

On a recently drilled well (Higgins #19 - January 2004) a new type of hybrid-style waterfrac treatment was attempted. A hybrid treatment consists of a large slickwater pad, employed to create long fractures using thin fluids, followed by crosslinked gel and proppant with the hope that the thicker fluid will transport proppant far down the fracture length thus providing improved propped fracture lengths. A true waterfrac treatment using only slickwater may have been adequate given the very low reservoir permeabilities and its advantage of eliminating gel damage to natural fractures; however, it was not possible to pump this type of treatment given the use of high-density Bauxite, which will cause substantial settling and proppant transport problems when pumped with slickwater.

The general goal of the hybrid treatment was to achieve longer fractures by pumping larger treatments (8,000 bbl of fluid with more than 200 klb of proppant) while maintaining adequate conductivity and minimizing gel damage to the natural fracture system. A less aggressive proppant ramp starting at 0.25

ppg to a maximum of 2 ppg was used to minimize proppant entry problems, which enhances the chances of creating a longer fracture. Also, the use of a large slickwater pad (40%) and low polymer concentration crosslinked gel (32# Vistar system) was used to help minimize gel damage (compared to 50 and 60 lb/Mgal gels) while still providing adequate proppant transport capabilities. CO₂ was not added in this type of treatment. It is not clear at this point if this new type of treatment resulted in better hydraulic fracture performance although it did appear to facilitate placing a larger fracture treatment with reduced risk of screenout.

In most wells the perforations were placed opposite of natural fractures in the Weber sections (from FMI logs). This perforation strategy will usually result in six to nine clusters of perforations for the Upper Weber and Lower Weber each (if completed). The Higgins # 19 was perforated differently with only two clusters of 20 ft perforated intervals in the higher porosity sections of the Weber sands. At this point it appears that different perforation strategies have little impact on the degree of fracture complexity as all wells show high fracturing net pressures. In all cases, the Dolomite (if not included with the fracture treatment of the Lower Weber, i.e., TR 124) is perforated and matrix acidized after the fracture treatment in the Upper Weber has been completed. The available short-term gas flow rates from the Upper Weber (all zones are usually commingled) are in the range of 800 MCFD to 2,000 MCFD at 400 psi to 500 psi surface flowing pressures. The Dolomite contributes to most of the gas flow rate, lifting the well production to rates as high as 18 MMCFD in some wells.

The Higgins 17 well was acid fracturing treated to target the Dolomite pay zone on April 21, 2004. Fracture growth behavior in the region is found very complex – fracture modeling analysis for the Higgins 17 acid treatment indicated a high net pressure of 2,300 psi and complex fracture growth of six multiple fractures. Unlike propped fracture treatments, acid fracture treatments do not run into any risk of screenout. The Higgins 17 acid fracture treatment was executed to completion with a treatment schedule consisting of 1,197 bbl of linear and crosslinked pad and 1,495 bbl of 15%HCl gelled acid. There was no wellhead pressure during the first nine minutes of pumping, which indicated that the wellbore was partially filled prior to the treatment and that the reservoir pressure was lower than expected.

Figure 3. Typical fracture treatment data for conventional CO₂ frac: Table Rock 124 Upper Weber

3.2 Fracture Engineering

A total of seven treatments in five wells were analyzed in this study. **Table 1** to **Table 3** summarize the most important fracturing treatment information from all study wells. Fracture closure pressure is generally about 0.66 to 0.69 psi/ft in the Upper Weber (with the exception of 0.8 psi/ft in the TR 123). The “combination” frac treatment of Upper Weber and Dolomite in the TR 124 showed a slightly lower closure of 0.62 psi/ft, which is probably more representative of the Dolomite since its perforations were the uppermost set. Closure pressure could not be determined in the Higgins #19 Lower Weber frac attempt since leakoff was slow and fracturing pressures were 1.11 psi/ft. To model the frac, upward growth in Higgins 17, the following stress data were used: 0.623 psi/ft for dolomite, 0.75 psi/ft for shale, 0.80 psi/ft for sandstone below Dolomite, and 0.70 psi/ft for all other sandstone formations.

Fracturing net pressures are generally very high ranging from about 500 psi to 3,500 psi in the mini-fracs and up to 5,000 psi in the main treatment (the screenout in the TR 124 Lower Weber and Dolomite may not reflect the “true” net pressure in the main frac body). ISIP gradients can vary substantially up to 1.1 psi/ft after the mini-frac. The two treatments with the highest ISIP (TR 123 Upper Weber and Higgins #19 Lower Weber) could not be successfully pumped due to pressure limitations. Successful treatments have mini-frac ISIPs in the range of 0.69 to 0.82 psi/ft. ISIPs at the end of the treatments range from about 0.86 psi/ft to as high as 1.33 psi/ft.

Except the acid frac treatment on Higgins 17, all other jobs had substantial net pressure increases throughout the treatment ranging from about 2,300 psi to over 3,400 psi (not counting the 9,000 psi increase for the screenout in the TR 124 LW and Dolomite). High fracturing pressures and net pressures are usually a guarantee for very complex hydraulic fracturing. In this field these circumstances have frequently resulted in:

- Inability to pump the treatments below the pressure limitations or
- Substantial pressure increases during the job due to small fracture widths as proppant is entering the fracture, eventually leading to screenouts

Table 1. Summary of Fracture Treatments: Diagnostic Injections

Well	Zone	Top Perf MD	Btm Perf MD	Diagnostic Injection-Frac Summary					
		(ft)	(ft)	Cls P psi	Eff (%)	Cls Grd psi/ft	ISIP(BH) psi	ISIP Grd psi/ft	Net P psi
TR 123	UW	17350.0	17480.0	13999	35%	0.80	15963	0.92	1964
TR 124	LW +DOL	17484.0	17726.0	10842	30%	0.62	14426	0.82	3584
TR 124	UW	17114.0	17340.0	11899	11%	0.69	13435	0.78	1536
TR 125	UW	17448.0	17750.0	11556	32%	0.66	13668	0.78	2112
Higgins 19	LW	18068.0	18144.0	n.a.	n.a.	n.a.	20024	1.11	n.a.
Higgins 19	UW	17474.0	17660.0	11511	40%	0.66	12044	0.69	533
Higgins 17	DOL	17967.0	17975.0	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.

Table 2. Summary of Fracture Treatments: Propped and Acid Frac Treatment

Well	Zone	Propped/Acid Frac Treatment Summary							
		Vol bbls	Rate bbls/min	Prop klbs	ISIP(BH) psi	ISIP Grad psi	Net P psi	Screen Out?	Net P Increase psi
TR 123	UW	1038.0	30 to 40	2	18309	1.05	4310	y	2346
TR 124	LW +DOL	3414.0	30.0	101	23391	1.33	12549	y	8965
TR 124	UW	3735.0	30.0	157	16812	0.98	4913	y	3377
TR 125	UW	3700.0	30.0	153	16182	0.92	4626	n	2514
Higgins 19	LW	5014.0	30 to 6	3	20228	1.12	n.a.	y	n.a.
Higgins 19	UW	7966.0	44.0	221	15091	0.86	3580	n	3047
Higgins 17	DOL	2692.0	26.0	0	13491	0.75	2300	n	n.a.

Table 3. Summary of Fracture Treatments: Comments

Well	Zone	Top Perf MD	Btm Perf MD	Comments
		(ft)	(ft)	
TR 123	UW	17350.0	17480.0	Borate x-link Gel; could not pump due to pressure limit
TR 124	LW +DOL	17484.0	17726.0	25% CO2 low PH 50-60# x-link; Screen-out
TR 124	UW	17114.0	17340.0	25% CO2 low PH 50-60# x-link; Pressure rise as proppant enters frac
TR 125	UW	17448.0	17750.0	25% CO2 low PH 50-60# x-link; Pressure rise not as extreme
Higgins 19	LW	18068.0	18144.0	Hybrid Frac- Slickwater/Vistar 3200; could not pump due to pressure limit
Higgins 19	UW	17474.0	17660.0	Hybrid Frac- Slickwater/Vistar 3200
Higgins 17	DOL	17967.0	17975.0	Acid Frac of alternating 15%HCl Gelled acid & 30#Pur-Gel III pad stages

Table 4. Summary of Fracture Analysis Results

Well	Zone	Prop/Etech	Prop/Frac	Conductivity (frac system)	Multiple Fracture Settings
		Length (ft)	Height (ft)	(mD-ft)	Volume-Leakoff-Opening
TR 123	UW	0	0	0	14-8-14
TR 124	LW +DOL	85	164	880	16-14-16
TR 124	UW	119	231	715	7-9-7
TR 125	UW	150	302	1120	10-5-10
Higgins 19	LW	79	104	0	60-5-60
Higgins 19	UW	292	272	770	5-9-5
Higgins 17	DOL	223	360	384	6-1.2-6

Table 4 shows a summary of the fracture modeling results. All fracture modeling was performed using the 3-dimensional hydraulic frac simulator FracproPT. Pressure-dependent leakoff (cross-cutting fissures opening at high injection pressures) is present in most of the falloffs, which is consistent with the presence of natural fractures leading to multiple complex fracturing. In conjunction with high net pressures this is an indication of far-field fracture complexity (multiple fractures), which can severely limit fracture extent (**Figure 4**). Near-wellbore fracture complexity (tortuosity), which manifests itself as a friction pressure, was moderate in most cases and does not appear to be the main problem for treatment execution. Every treatment had to be modeled with a large degree of fracture complexity, which included both multiple competing fractures and increasing leakoff throughout the job as fissures open.

Figure 4. Illustration of fracture complexity: Near-wellbore versus far-field

Figure 5 shows an example of a G-function analysis plot (from TR 124 Lower Weber/Dolomite) indicating significant pressure-dependent leakoff (PDL, where oblique-oriented natural fissures open

during the fracturing process). Such a behavior in conjunction with high net pressures is strong evidence for very complex fracture growth.

The following section details all the individual fracture treatments with graphs of treatment data, fracture closure analysis, net pressure matches and resulting fracture geometry.

3.2.1. Table Rock #123 Upper Weber Frac Attempt

In this well it was not possible to successfully fracture treat the Upper Weber as meaningful injection rate could not be established due to surface pressure limitations of 12,000 psi. **Figure 6** clearly shows decreasing injectivity through the course of the pad resulting in a premature termination of the treatment without any meaningful amounts of proppant being pumped. **Figure 8** shows that near-wellbore tortuosity and perforation friction are moderate and not the root cause of high injection pressures. The net pressure match shows high frac complexity (**Figure 9**) resulting in a very short 50 ft un-propped fracture (**Figure 10**). Following this failed fracture attempt, the Dolomite was perforated and acidized resulting in initial flow rates of almost 6 MMCFD.

Figure 10. Model fracture geometry: Table Rock 123 Upper Weber Frac attempt

3.2.2. Table Rock #124 Lower Weber and Dolomite

In this well the Lower Weber and Dolomite were perforated and fracture treated together with a 25% CO₂-assisted 50 to 60 lb/Mgal crosslinked gel (YF 850/860LPH). The Dolomite perforations were the uppermost set. The mini-frac pressure falloff analysis (**Figure 12**) indicated rapid fluid leakoff with a fairly low closure stress of about 0.62 psi/ft, which is probably an indication that the fracture treatment was mainly located in the Dolomite (uppermost perforated interval with lowest stress and pore pressure). The falloff also indicates pressure-dependent leakoff, an indication of fissure opening and susceptibility to complex fracturing. The treatment data in **Figure 11** shows that bottomhole pressures immediately increase as 0.5 ppg 30/60 bauxite enters the fracture. This is an indication of very small fracture widths and high fracture complexity resulting in a continuous rapid increase of treating pressures and screenout. As the proppant is unable to move substantially into the fractures, it accumulates and eventually creates a barrier leading to the screenout. The net pressure was matched using high fracture complexity and is shown in **Figure 14**.

The resulting model fracture geometry indicates a very short 85-ft fracture. **Figure 20** shows an after-frac tracer log in this well indicating that the model-predicted fracture geometry is not correctly predicting the position of the fracture along the wellbore (model is centered around Dolomite and upper perforations). The tracer indicates that, except for the lowest set, all perforations took fracturing fluid and proppant; however, the tracer is mainly confined to the perforation clusters without connection at the wellbore supporting the presence of multiple fractures. Initial gas rates from this completion were about 4.5 MMCFD. The results of the post-frac PBU indicated very poor fracture stimulation and are presented in Section 3.3.

Figure 11. Treatment data: TR 124 Lower Weber and Dolomite

Figure 12. Fracture closure analysis: TR 124 Lower Weber and Dolomite

Figure 15. Fracture geometry: Table Rock 124 Lower Weber and Dolomite

3.2.3. Table Rock #124 Upper Weber

The Upper Weber was fractured with a 25% CO₂-assisted 50 to 60 lb/Mgal crosslinked gel (YF 850/860LPH). The mini-frac pressure falloff analysis (**Figure 17**) indicates rapid fluid leakoff with a closure stress of about 0.69 psi/ft. Although not as pronounced as in the other cases, the falloff exhibits some pressure-dependent leakoff. Similar to the lower stage, the treatment data in **Figure 16** shows that bottomhole pressures immediately increase as 0.5 ppg 30/60 bauxite enters the fracture indicating small fracture widths and high fracture complexity. Treating pressures continued to rise but in this case the treatment was flushed and pumped to completion. The net pressure was matched using high fracture complexity and is shown in **Figure 18**.

The resulting model fracture geometry indicates a very short 120 ft fracture (**Figure 19**). The after-frac tracer log for this stage (**Figure 20**) indicates that the two lowest set of perforations took most of the fracturing fluid and proppant, although some tracer was also found in some of the upper perforations. When comparing the tracer log with the fracture modeling results it is unclear if the tracer is showing the total fracture height since fractures may not be fully aligned with the wellbore. If the fracture height covers the interval from the uppermost indication of tracer to the lowest, it coincides fairly well with the overall modeled fracture height of 230 ft. The tracer log generally shows that tracer is confined to each set of perforations with no apparent connection between. This may indicate separate fractures not growing together. In the Lower Weber only the lowest set of perforations was not stimulated. The tracer log appears to confirm the conclusion from fracture modeling that fracture complexity is high. Except for the exact position along the wellbore, the overall fracture heights of the top and bottom tracer roughly correspond to the overall fracture model heights. Once all zones were commingled, the well produced at an initial rate of about 6.5 MMCFD, with the Upper Weber contributing about 1.5 to 2 MMCFD.

Figure 16. Treatment data: Table Rock 124 Upper Weber

Figure 17. Fracture closure analysis: Table Rock 124 Upper Weber

Figure 18. Net pressure match: Table Rock 124 Upper Weber

Figure 19. Model fracture geometry: Table Rock 124 Upper Weber

Figure 20. RA tracer log in Table Rock #124

3.2.4. Table Rock #125 Upper Weber

In this well only the Upper Weber was fracture treated using a 25% CO₂-assisted 50 to 60 lb/Mgal crosslinked gel (YF 850/860LPH). The mini-frac pressure falloff analysis (**Figure 22**) indicated rapid fluid leakoff with a closure stress of about 0.66 psi/ft. The falloff also indicates pressure-dependent leakoff, an indication of fissure opening and susceptibility to complex fracturing. The treatment data in **Figure 21** shows that bottomhole pressure immediately increases as 0.5 ppg 30/50 bauxite enters the fracture. Again, this is an indication of very small fracture widths and high fracture complexity resulting in a continuous rapid increase of bottomhole treating pressures. In this case, the fracture treatment was pumped to completion without screenout. The net pressure was matched using high fracture complexity and is shown in **Figure 23**.

The resulting model fracture geometry indicates a very short 150 ft fracture (although longer than in the previous TR 124 treatment (**Figure 24**)).

Figure 24. Model fracture geometry: TR 125 Upper Weber

3.2.5. Higgins #19 Lower Weber

This treatment could not be pumped as planned due to extremely high treating pressures, which reached the surface pressure limitation almost immediately after pumping was started. The design in this treatment was different than in the previous Table Rock wells and is similar to hybrid fracs pumped in East Texas. It included pumping a large slickwater pad followed by a crosslinked 32 lb/Mgal crosslinked gel (Vistar 3200) and lower proppant concentrations of 0.25 ppg to 2 ppg. The mini-frac injection ISIP was already 1.106 psi/ft (**Figure 25**). The mini-frac pressure falloff analysis (**Figure 26**) indicated pressure-dependent leakoff which, in conjunction with high ISIPs, is a recipe for complex fracturing, possibly even in different planes (vertical, subvertical, or even horizontal). Entry friction was not a problem as tortuosity was low. It was not possible to determine closure stress since it was not reached within the time-frame of the falloff (one hour).

The treatment data in **Figure 27** shows the difficulties of pumping the treatment. Surface treating pressures were continuously just below the limit, and when crosslinked gel was pumped the higher friction pressures required a rate reduction down to 5 bpm. At this point, it was decided to revert back to linear gel, which helped re-establish injectivity; however, after pumping just 3 klb of proppant it was decided to shutdown the treatment since pressures were continuously rising towards the maximum allowable pressure. The net pressure was matched using high fracture complexity and is shown in **Figure 28**. Even though virtually no proppant was placed in the formation, the treatment did manage to inject a large amount of fluid (5,000 bbl); however, it is unlikely that an un-propped fracture will be successful at this depth and reservoir conditions unless it manages to enhance and maintain the conductivity of existing natural fractures under production conditions. The net pressure match is shown in **Figure 28** and the resulting model fracture geometry in **Figure 29** indicating an un-propped 300 ft fracture.

3.2.6. Higgins #19 Upper Weber

The Upper Weber treatment behaved completely differently than the Lower Weber. Treating pressures were about 6,000 psi lower than in the Lower Weber and posed no problems for treatment execution. Due to the high pressures in the Lower Weber treatment and operational considerations, the Lower Weber perforations were left open for the Upper Weber fracture treatment with the hope that the stress differential in the two zones would be enough for diversion into the upper interval.

The mini-frac injection ISIP was only 0.69 psi/ft (**Figure 30**). The mini-frac pressure falloff analysis (**Figure 31**) indicated pressure-dependent leakoff and a closure of about 0.66 psi/ft. The step-down test after the mini-frac indicated no tortuosity.

The treatment data in **Figure 30** shows that the treatment was pumped as planned, with no significant pressure increase as proppant enters the fracture. The overall treating pressures still increased by about 3,000 psi from mini-frac to the end of the treatment as a result of increasing fracture complexity (increase was mainly during the pad). The net pressure was again matched using high fracture complexity and is shown in **Figure 32**. The model fracture geometry in **Figure 33** indicates a propped fracture length of about 300 ft.

Figure 34 shows the after-frac tracer log in the Higgins #19 indicating that the Upper Weber intervals took the majority of the fluid and proppant; however, there appears to be also some small-scale stimulation in the Lower Weber. Interestingly, the tracer distribution again shows very limited height growth at the wellbore around the perforations with no apparent connection, pointing to the possibility of independent fracture growth at each set of perforations.

It is not clear at this point if this new type of treatment resulted in better hydraulic fracture performance although it did appear to facilitate placing a larger fracture treatment with reduced risk of screenout. Two weeks of flowback for the Weber completions indicated initial gas flow rates of about 800 to 1,000 MCFD at 150 psi to 600 psi flowing wellhead pressures.

Figure 32. Net pressure match: Higgins 19 Upper Weber frac

Figure 33. Model fracture geometry: Higgins 19 Upper Weber frac

Figure 34. RA tracer log in Higgins #19

3.2.7. Higgins #17 Dolomite

The prolific Dolomite pay zone in the Higgins 17 well was treated by acid fracturing on April 21, 2004. A tracer log was run to understand fluid coverage and fracture growth in the near-wellbore region for the acid fracture treatment. As shown in the after-frac tracer log in **Figure 35**, the treatment fluids were taken over a very large wellbore interval from a depth (MD) of 17,610 ft to 18,040 ft. Note from **Table 1** that the perforation interval is located between 17,967 and 17,975 ft. Confirmed from the operator, the fluid coverage over such a long interval was caused by a poor cement job behind the casing.

Figure 35. RA tracer log in Higgins #17

Unlike propped fracture treatments, acid fracture treatments do not run into any risk of screenout. As shown in **Figure 36**, the treatment was executed to completion and a total volume of 2,692 bbl of fluids was pumped. No mini-frac was conducted prior to the main acid treatment. The treatment schedule consisted of 1,197 bbl of pad (239 bbl of linear gel in the first pad stage and 960 bbl of 30# PURGEL III crosslinked gel in the remaining stages) and 1,495 bbl of 15% HCl gelled acid. The treatment was pumped by alternating pad and acid stages to facilitate differential etching and deep acid penetration. The treatment data indicated a surface ISIP of 5,765 psi and an ISIP gradient of 0.75 psi/ft. Note that there was no wellhead pressure during the first nine minutes of pumping, which indicated that the wellbore was partially filled prior to the treatment and that the reservoir pressure was lower than expected.

Fracture growth behavior in the region is very complex. For example, in Higgins # 19 the propped treatment in the Lower Weber could not be pumped due to extremely high treating pressures fracture, and multiple fracture growth with excessive fluid leakoff and very high net pressure was observed in the Upper Weber during the propped treatment. As summarized in **Table 2** and **Table 4**, fracture modeling analysis for the Higgins 17 acid treatment indicated a high net pressure of 2,300 psi and complex fracture growth of six multiple fractures, but a low leakoff factor of 1.2. To model the frac upward growth in the Higgins 17, the following stress data were used: 0.62 psi/ft for Dolomite, 0.75 psi/ft for shale, 0.80 psi/ft for the sandstone layer right below the Dolomite, and 0.70 psi/ft for all other sandstone formations. The same rock mechanical properties such as Young's modulus from Higgins 19 were used for the modeling in Higgins 17. The Dolomite pay zone was initially (prior to the acid fracture treatment) estimated to have a permeability around 1.0 – 5.0 mD; however, net pressure match of the treatment data indicated a lower permeability of 0.5 mD. The net pressure was matched and is shown in **Figure 37**.

Figure 37. Net pressure match of Higgins 17 acid fracture treatment data

The predicted fracture geometry and acid-etched profile obtained from the net pressure match are shown in **Figure 38** and **Figure 39**, which indicate the following modeling results: fracture half-length = 326 ft, total fracture height = 360 ft, depth to fracture top = 17,682 ft, depth to fracture bottom = 18,042 ft, etched fracture half-length = 223 ft, average conductivity = 384 mD-ft, and $FcD = 3.5$. Acid spending is a function of reaction rate, acid concentration and temperature. As a result, the maximum acid-etched conductivity did not occur in the near-wellbore region: a maximum conductivity of 1,130 mD-ft at a distance of 127 ft away from the wellbore. If a CFA (closed fracture acidizing) stage was pumped at the end of the job, the near-wellbore conductivity could have been improved. It is worth pointing out that the overall fracture height is over 40 times larger than the net Dolomite zone thickness, which is only 8.4 ft. The vast fracture area that was covered by the acid includes sand/shale formations, which are not reactive with HCL acid.

Figure 38. Model fracture geometry for Higgins 17

Figure 39. Acid etched fracture conductivity and length for Higgins 17

Based on modeling results in **Figure 38** and **Figure 39**, production forecast and economic analysis for the acid fracture treatment in the Higgins 17 were carried out. The following assumptions were used for the

study: drainage area = 640 acres, net pay = 8.4 ft, water saturation = 35%, porosity = 11%, initial reservoir pressure = 5,800 psi, etched fracture half-length = 223ft, average etched conductivity = 384 mD-ft, gas price = \$3.00, discount rate = 12%, cost of the acid fracture job = \$150,000, reservoir permeability = 0.5 mD, and wellhead flowing pressure = 300 psi. As shown in **Figure 40**, early gas production yielded about 2 MMscft/day using the actual post-treatment flowback/production pressure. The predicted production is consistent with actual data. Also shown in the same figure, the predicted one-year NPV is \$1.5 million dollars.

Figure 40. One-year gas production and NPV Forecast

Two acid fracture models (FracproPT default and ADP) were used to study the impacts of acid-etched length/conductivity prediction uncertainties on post-treatment production. Both models use the same fracture geometry predicted by the FracproPT 3-D fracture growth model. The two models differ in acid transport – the default model tracks the acid inside the fracture using elliptical rings with each ring representing an acid stage or a fraction of an acid stage, and the ADP model assumes piston-like acid transport and that the acid covers the entire fracture height. The default model could over-predict acid etched length, while the ADP model tends to under-predict acid etched length. The ADP modeling prediction is shown in **Figure 41**. Using an end-point conductivity value of 200 mD-ft as the cut-off point, the following results were obtained from the ADP model: an etched fracture half-length of 107 ft, an average conductivity of 298 mD-ft, and Fcd of 5.6. The etched fracture half-length predicted from the ADP model is 50% of that from the FracproPT default model; however, as shown in **Figure 42**, the production rate from the ADP model is only about 10% lower than that from the FracproPT default model.

Figure 41. Acid etched fracture conductivity and length predicted by the ADP model

Figure 42. Production comparison based on the FracproPT default and ADP acid models

Prior to the acid fracture treatment, the Dolomite pay zone was initially estimated to have a permeability around 1.0 – 5.0 mD; however, post-treatment net pressure analysis indicated a lower permeability of 0.5 mD. Permeability is a major factor in affecting reservoir performance. To evaluate permeability

uncertainties on production, simulations with reservoir three permeability values of 0.5, 1.0 and 5.0 mD were conducted. As shown in **Figure 43**, the reservoir permeability has dramatic impacts on gas production. The short-term post-treatment production of 2 MMscfd seems to match well the production forecast with a Dolomite permeability of 0.5 mD.

3.2.8. Post-Frac PBU in Table Rock #124 Lower Weber and Dolomite

The post-frac PBU in the Table Rock #124 was performed for the Lower Weber and Dolomite completion. The well had been on production for about five days with gas rates climbing to about 4.5 MMCFD. The analysis and final match of the post-frac PBU is shown in **Figure 44** and the results are summarized in **Table 5**. The PBU does not indicate the presence of a conductive hydraulic fracture. There is no indication of formation linear flow at any time during the buildup. The pressure derivative (red curve) flattens out fairly quickly indicating immediate radial flow in the formation. It appears that this buildup is mainly showing the flow contribution from a slightly stimulated Dolomite (skin is about -3) with a permeability of about 0.63 md (19 md-ft) but there is no evidence of a conductive hydraulic fracture at this point of production.

As discussed previously, the fracture treatment incurred a screenout with a possible model length of only 100 ft. Since the tracer log showed that all perforations accepted fluid and proppant, it is very likely that at the time of the PBU, the hydraulic fracture had not cleaned up yet and was still damaged from the treatment as a result of high screenout pressures that may have caused a “polymer squeeze-off” into the natural fractures. Another possibility is that the complexity of the hydraulic fractures may be so extreme that fractures are very short and in different planes (“shattered zone” around the wellbore), negating any dominant linear flow from fractures in a single plane.

Table 5. Post-Frac Analysis Results Table Rock #124

xf (ft)	k (md)	kh (md-ft)	Fc (md-ft)	FcD	Skin	Pi (psi)
0	0.629	18.9	0	0	-3.06	4949

Figure 44. Post-frac PBU analysis in Table Rock #124