**Stimulation Technologies for
Deep Well Completions**

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National Energy Technology Laboratory
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**By:
Pinnacle Technologies, Inc.
Park North Technology Center
219 Airtex Boulevard
Houston, Texas 77090**

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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. The case study done with Anadarko and ChevronTexaco in the Table Rock Field in Wyoming was reported in Technical Progress Report No. 3. This report details work done with ConocoPhillips in the Jennings Ranch Field in Texas.

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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 stimulation technology 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 ConocoPhillips. This study focused on a deep gas productive horizon operated by ConocoPhillips in the Jennings Ranch Field, Zapata County, Texas. The primary targets are the Lobo 6, Lobo 1 and Lobo Stray sands. This study focused on the deeper Lobo 6 interval at depths of roughly 12,200 feet to 12,500 feet. The formation is highly over-pressured with pressures of about 10,200 psi (0.81 psi/ft) and fracturing pressures of about 0.93 psi/ft to 0.96 psi/ft. Porosities are about 16% to 21% with water saturations of 45% to 55%. Net pay can vary from about 20 feet to over 100 feet. All wells are completed with crosslinked gel fracture treatments using ceramic proppants. Multiple target zones are generally commingled, with a typical well producing about 7 to 8 MMCFD initially, and declining fairly fast to 2 MMCFD or less within one year. The wells are located in 80 to 120 acre fault blocks with three to four wells per fault block (20 acre to 40 acre well spacing). Approximately sixty to seventy wells were drilled over the last five years. The study included a total of six wells drilled and completed from 1999 to 2001.

The main conclusions are that modeled propped fracture lengths are approximately 400 to 660 feet, with fracture heights slightly larger than the perforated interval. Fracture treatments do not show any obvious problems with fracture length generation or proppant placement. Production analysis, although somewhat non-unique, indicates that effective fracture lengths could be as long as the ones calculated with the fracture model.

All wells show fairly rapid production declines, which is normal in highly over-pressured reservoirs with fracture stimulation; however, two wells showed higher production declines, which may indicate an impairment of either reservoir or fracture flow capacity since production could not be modeled with constant reservoir/fracture properties. It is not clear if the impairment was caused due to stress-sensitive reservoir permeability (high drawdowns) or a deteriorating hydraulic fracture (reduced proppant conductivity due to higher effective stress, fines migration into proppant pack, multi-phase flow). Flow tests with bottomhole gauges followed by pressure buildup tests could be used to diagnose if the problem is due to a deteriorating hydraulic fracture.

Production data shows reservoir linear flow for about one to two years indicating effective fracture stimulation. This period is followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions. Estimated drainage areas highly depend on assumptions of hydrocarbon pore volume (porosity, net pay, water saturation) but, using the numbers provided by the operator, drainage areas were estimated to range from as low as seven acres to about 70 acres.

The biggest opportunity in this drilling program appears to be fracture optimization as a function of actual well spacing. Preliminary generic optimization simulations show the potential for job size reductions as well spacing is reduced. It also indicates that current job sizes may be close to the optimum if well spacing is around 40 acres but for fault blocks with well spacing smaller than 40 acres job sizes could potentially be reduced.

2. Conclusions and Recommendations

1. Propped fracture lengths are modeled to be approximately 400 to 660 feet, with fracture heights slightly larger than the perforated interval. Fracture treatments did not encounter any problems, and do not show any obvious problems with fracture length generation or proppant placement. These model geometries have not been confirmed with actual fracture geometry measurements such as microseismic and tiltmeter fracture mapping. Production analysis, although somewhat non-unique, indicates that effective fracture lengths could be as long as the ones calculated with the fracture model.
2. Moderate fracture complexity was observed on most treatments but does not seem to play a major role in proppant placement or severe reduction of fracture length. Estimates of actual fracture conductivities are difficult and limited by both fracture complexity issues and actual effective conductivities under flowing conditions; however, based on initial production and its decline, four out of six wells show no evidence that fracture conductivities have been severely impaired in the first year of production.
3. All wells show fairly rapid production declines, which is normal in highly over-pressured reservoirs with fracture stimulation; however, in two wells (C-10 and C-12) production declines were too high, which may indicate an impairment of either reservoir or fracture flow capacity since production could not be modeled with constant reservoir/fracture properties. It is not clear if the impairment was caused due to stress-sensitive reservoir permeability (high drawdowns) or a deteriorating hydraulic fracture (reduced proppant conductivity due to higher effective stress, fines migration into proppant pack, multi-phase flow; note: these two wells were stimulated with Econoprop). If possible, single zone flow tests followed by a pressure buildup test could be used to diagnose if the problem is in fact due to a deteriorating hydraulic fracture or is simply a stress-sensitive reservoir permeability issue.
4. Production analysis indicates that all wells have some degree of reservoir linear flow behavior once clean-up effects have subsided and wells are flowed at fairly constant flowing pressures. The linear flow regime lasts about one year to two years in most wells, indicating effective fracture stimulation. This period is followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions. Estimated drainage areas highly depend on assumptions of hydrocarbon pore volume (porosity, net pay, water saturation) but using the numbers provided by the operator were estimated to range from as low as 7 acres to 70 acres with flow capacity (kh) ranging from about 0.1 md-ft to 4 md-ft.
5. Fracture optimization depends heavily on well spacing and reservoir properties such as permeability. Generic fracture optimization simulations show that the 80-acre spacing optimum frac size is about 420 klb, for 40-acre spacing the optimum size decreases to about 240 klb (which is close to current designs - **Figure 1**), and for continued infill drilling to 20 acre spacing, optimum size would decrease to about 130 klb (**Figure 2**). These simulations were performed for a representative set of reservoir properties and economic assumptions that may require some fine-tuning but were done to demonstrate the importance of fracture optimization for infill drilling.

Figure 1. Fracture optimization generic well 40 acre spacing

Figure 2. Fracture optimization generic well 20 acre spacing

3.2 Fracture Engineering and Production Analysis

3.2.1 Fracture Engineering

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between 0.93 psi/ft to 0.96 psi/ft for both the mini-fracs and main treatments. Assuming 0.87 psi/ft closure stress in all other wells, fracturing net pressures are between 750 psi to 1,000 psi for the mini-fracs with a fairly low increase of 10 psi to 300 psi during the main treatment. This indicates that current fracture treatment designs and completion methodologies are successful in placing jobs without any major pressure increases.

Four treatments were pumped using 20/40 Econoprop (lowest strength ceramic proppant) and two with a higher strength 20/40 Carboprop (C-21 and C-24). Fracturing fluids were 50 to 60 lb/Mgal crosslinked gels, tapered off to a 35-lb/Mgal system at the end of the treatment. Maximum proppant concentrations were 5 to 6 ppg with total job sizes being about 270 to 430 klb of proppant depending on gross zone thickness. Pump rate was about 40 bbl/min and total slurry volume about 2,400 bbl to 3,500 bbl with pad sizes of 25% to 30%.

Table 1. Summary of Fracture Treatments: Diagnostic Injections

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Diagnostic Injection-Frac Summary					
				Cls P psi	Eff (%)	Cls Grd psi/ft	ISIP(BH) psi	ISIP Grd psi/ft	Net P psi
C-10	L6	12201.0	12350.0	10709	30%	0.87	11451	0.93	742
C-12	L6	12494.0	12617.0	n.a.	n.a.	n.a.	11829	0.94	798
C-18	L6	12220.0	12360.0	n.a.	n.a.	n.a.	11565	0.94	851
C-19	L6	12253.0	12431.0	n.a.	n.a.	n.a.	11786	0.95	1009
C-21	L6	12496.0	12744.0	n.a.	n.a.	n.a.	11728	0.93	748
C-24	L6	12394.0	12538.0	n.a.	n.a.	n.a.	11855	0.95	961

Table 2. Summary of Fracture Treatments: Propped Treatment

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Propped Treatment Summary								
				Vol bbls	Rate bbls/min	Prop klbs	ISIP(BH) psi	ISIP Grad psi	Net P psi	Screen Out?	Net P Increase psi	Comments
C-10	L6	12201.0	12350.0	3425.0	40.0	426	11746	0.96	1037	n	295	Econoprop 20/40; YF850-835
C-12	L6	12494.0	12617.0	2527.0	36.0	276	11852	0.94	821	n	23	Econoprop 20/40; Med 60# to Med 40#
C-18	L6	12220.0	12360.0	2464.0	40.0	283	11575	0.94	861	n	10	Econoprop 20/40; Med 45# to Med 35#
C-19	L6	12253.0	12431.0	3197.0	40.0	350	11852	0.96	1075	n	66	Econoprop 20/40; Med 50# to Med 35#
C-21	L6	12496.0	12744.0	3220.0	45.0	400	11896	0.94	916	n	168	Carboprop 20/40; Med 50# to Med 35#
C-24	L6	12394.0	12538.0	3039.0	43.0	365	11911	0.96	1017	n	56	Carboprop 20/40; Med 50# to Med 35#

Table 3 shows a summary of the fracture modeling results. All fracture modeling was performed using the 3-dimensional hydraulic frac simulator FracproPT. Fracturing net pressures were fairly high, indicating some degree of far-field fracture complexity (multiple fractures), which could limit fracture extent (**Figure 6**). The last column of **Table 3** summarizes the fracture complexity settings. These numbers are not meant to be exact representations of the number of multiple fracture branches but indicate that the degree of complexity is moderate in four wells and two wells had no meaningful complexity (C-12 and C-18). Near-wellbore fracture complexity (tortuosity) was fairly low on all treatments, indicating no fracture width problems for proppant as it enters the fracture.

Table 3. Summary of Fracture Analysis Results

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Prop Length ft	Prop Height ft	Conductivity (frac system) md-ft	Multiple Fracture Settings Volume-Leakoff-Opening
C-10	L6	12201.0	12350.0	405	178	2115	3-3-3
C-12	L6	12494.0	12617.0	603	221	451	1-1-1
C-18	L6	12220.0	12360.0	663	204	353	1-1-1
C-19	L6	12253.0	12431.0	419	223	820	5-4-5
C-21	L6	12496.0	12744.0	510	235	1568	2-3-2
C-24	L6	12394.0	12538.0	431	207	1752	4-4-4

Modeled propped fracture lengths are estimated to be about 400 to 660 feet with propped fracture heights between 175 ft and 235 ft showing some limited growth above and below the target interval but all-in-all fairly contained. Conductivities in **Table 3** are ideal values and do not account for non-darcy and multi-phase flow corrections and assume that multiple fracture branch conductivity is additive. Fracture model results have not been verified with independent far-field fracture diagnostics such as microseismic or tiltmeter fracture mapping since it has not yet been done in deeper, hotter South Texas environments.

3.2.2 Production Analysis

Table 4 summarizes the production analysis results for all six wells. The C-10 was the only well that produced the Lobo 6 by itself for three years. All other wells were immediately commingled with Lobo 1 sand above. The allocation of production to the Lobo 6 sand used in the analysis was provided by ConocoPhillips using production logs where available and bulk volume of hydrocarbons. All wells except the C-12 (only 17%), have a Lobo 6 contribution of over 50% (56% to 72 %). Net pay, porosity and water saturation estimates were provided by ConocoPhillips. The production analysis was performed using a single-phase, single-layer numerical reservoir simulator in FracproPT™. Non-darcy and multi-phase flow effects (assuming 10 bbl/MMCF liquid yield), and proppant embedment, were included in the simulation. Drainage area shape was assumed to be rectangular with the extent in the frac direction being slightly longer than the fracture length.

Graphs of the production analysis are presented in the following section under each individual well. It includes a log-log diagnostic plot of production versus time and a match of flowing pressures (production rates were used as input constraint in simulations). The plots indicate that all wells have some degree of reservoir linear flow behavior once cleanup effects have subsided and wells are flowed at fairly constant flowing pressures. The linear flow regime appears to last about one year to two years in most wells, followed by the onset of a depletion stem, which could be limited drainage from offset wells, geology and/or liquid loading conditions (**Figure 5**). Production analysis can be non-unique to some extent but in this case the use of the fracture model lengths appears to result in reasonable matches; however, production declines are fairly rapid, which is common in tight over-pressured reservoirs and is also an indication of reasonable fracture stimulation but in some cases (C-10 and C-12 wells) the decline was more than can be modeled with constant reservoir or fracture properties (**Figure 13** and **Figure 14**). In those cases the simulations were performed by reducing reservoir permeability by 75% as a function of effective stress (stress-sensitive permeability can occur in over-pressured reservoirs with large drawdowns). Of course, the reason for rapid declines could also be caused by a deteriorating hydraulic fracture (such as fines migration into the proppant pack, stress-sensitive behavior of frac conductivity, and multi-phase flow inside the fracture). These effects cannot be distinguished from production analysis alone. Other tests such as pressure transient tests combining a drawdown with a buildup could be used to evaluate hydraulic fracture quality.

Production analysis results in **Table 4** show a wide range of formation flow capacity (kh) ranging from less than 0.1 md-ft (C-10) to almost 4 md-ft (C-21) with drainage areas between 7 acres and 70 acres. Of course these results highly depend on the assumptions of net pay, porosity and water saturations.

Table 4. Summary of Production Analysis Results

Well	Zone	Top Perf MD (ft)	Btm Perf MD (ft)	Net Pay ft	Porosity %	Sw %	k md	kh md-ft	DA acres
C-10	L6	12201.0	12350.0	40	17	54	0.0900	3.60	70
C-12	L6	12494.0	12617.0	17	15	56	0.0400	0.68	54
C-18	L6	12220.0	12360.0	60	18	56	0.0150	0.90	45
C-19	L6	12253.0	12431.0	125	21	46	0.0014	0.18	10
C-21	L6	12496.0	12744.0	114	16	52	0.00038	0.043	7
C-24	L6	12394.0	12538.0	94	16	49	0.0065	0.61	16

Figure 6. Illustration of fracture complexity: near-wellbore versus far-field

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

3.2.3 Jennings Ranch C-10

The C-10 treatment was the only treatment where the mini-frac reached closure pressure. It was estimated to be about 0.87 psi/ft (**Figure 8**). **Figure 9** shows that near-wellbore tortuosity and perforation friction are fairly low (190 psi near-wellbore and 100 psi perforation friction at 25 bpm). The net pressure match is shown in **Figure 10**. Fracture length is estimated to be about 450 ft with fracture height slightly more than the perforated interval. The production match in **Figure 13** and **Figure 14** show how stress-sensitive permeability improves the quality of the flowing pressure match.

Figure 9. Step-down test analysis: Jennings Ranch C-10 Lobo 6

Figure 10. Net pressure match: Jennings Ranch C-10 Lobo 6

Figure 11. Model fracture geometry: Jennings Ranch C-10 Lobo 6

Figure 12. Log-log diagnostic plot of well production: Jennings Ranch C-10 Lobo 6

3.2.4 Jennings Ranch C-12

The net pressure match is shown in **Figure 17**. Fracture length is estimated to be about 600 ft with some downward growth below the perforated interval. Stress-sensitive permeability was also used in this case to improve the quality of the flowing pressure match.

Figure 17. Net pressure match: Jennings Ranch C-12 Lobo 6

Figure 18. Model fracture geometry: Jennings Ranch C-12 Lobo 6

Figure 19. Log-log diagnostic plot of well production: Jennings Ranch C-12 Lobo 6

Figure 20. Production match using model frac length and stress-sensitive permeability: Jennings Ranch C-12 Lobo 6

3.2.5 Jennings Ranch C-18

The net pressure match is shown in **Figure 23**. Fracture length is estimated to be about 660 ft with slight height growth around the perforated interval. In this case it was not necessary to model production with stress-sensitive permeability.

Figure 21. Treatment data: Jennings Ranch C-18 Lobo 6

Figure 22. Closure analysis: Jennings Ranch C-12 Lobo 6

Figure 23. Net pressure match: Jennings Ranch C-18 Lobo 6

Figure 24. Model fracture geometry: Jennings Ranch C-18 Lobo 6

Figure 25. Log-log diagnostic plot of well production: Jennings Ranch C-18 Lobo 6

Figure 26. Production match using model frac length and constant permeability: Jennings Ranch C-18 Lobo 6

3.2.6 Jennings Ranch C-19

The net pressure match is shown in **Figure 29**. Fracture length is estimated to be about 400 ft with slight height growth around the perforated interval. In this case it was not necessary to model production with stress-sensitive permeability.

Figure 27. Treatment data: Jennings Ranch C-19 Lobo 6

Figure 30. Model fracture geometry: Jennings Ranch C-19 Lobo 6

Figure 31. Log-log diagnostic plot of well production: Jennings Ranch C-19 Lobo 6

3.2.7 Jennings Ranch C-21

The net pressure match is shown in **Figure 35**. Fracture length is estimated to be about 500 ft with the fracture roughly covering the perforated interval. In this case it was not necessary to model production with stress-sensitive permeability.

Figure 37. Log-log diagnostic plot of well production: Jennings Ranch C-21 Lobo 6

Figure 38. Production match using model frac length and constant permeability: Jennings Ranch C-21 Lobo 6

3.2.8 Jennings Ranch C-24

The net pressure match is shown in **Figure 41**. Fracture length is estimated to be about 400 ft with the fracture height slightly more than the perforated interval. In this case it was not necessary to model production with stress-sensitive permeability.

Figure 40. Closure analysis: Jennings Ranch C-24 Lobo 6

Figure 41. Net pressure match: Jennings Ranch C-24 Lobo 6

Figure 42. Model fracture geometry: Jennings Ranch C-24 Lobo 6

Figure 43. Log-log diagnostic plot of well production: Jennings Ranch C-24 Lobo 6

3.3 Integration and Application of Results

3.3.1 Hydraulic Fracture Optimization

Current well spacing is specified to be about three to four wells in 80 acre to 120 acre fault blocks. Using the well information in the Jennings Ranch C-12, a generic well was created to investigate what the optimum fracture length would be given three different well spacings (80 acres, 40 acres, and 20 acres). Net pay was assumed to be 60 feet, porosity 18%, water saturation 50%, permeability 0.02 md and pore pressure 10,200 psi. Economic criteria were assumed to be \$4.00 flat gas price, 10% discount rate, and frac costs of about \$1.00 per pound of proppant with 1/3 being fixed costs and 2/3 being variable costs depending on treatment size. These numbers are just rough assumptions but are mainly used to highlight the importance of fracture optimization for continued infill drilling.

The results show that optimum fracture size depends heavily on well spacing. For 80 acre spacing optimum frac size is 420 klb (**Figure 45**), for 40 acre spacing the optimum size decreases to about 240 klb (which is close to current designs) (**Figure 46**), and for continued infill drilling to 20 acre spacing, optimum size would decrease to about 130 klb (**Figure 47**).