Methanol in Fracturing Fluid Enhances Southeastern New Mexico Stimulations

Hal Crabb III
Enron Oil & Gas Co.

L.W. Helm
Enron Oil & Gas Co.

Ron Willett
Halliburton Energy Services, Inc.

J.M. Terracina
Halliburton Energy Services, Inc.

Phillip C. Harris
Halliburton Energy Services, Inc.

Abstract
A study of stimulation techniques in the Morrow and Atoka formations was conducted because operators wanted to find a way to slow the anomalous decline in production from wells that were drilled and completed during the late 1970s and early 1980s.

Operators investigated completion practices used during this period and conducted pressure-transient analysis. They analyzed sidewall cores for mineralogy studies of the reservoir rock and sensitivity testing of water and acids.

From this study, we concluded that the completion fluids used were damaging the reservoir rock. Buildup analysis showed that most fracture treatments only reduced the positive skin present and rarely resulted in stimulation.

This study revealed the need for a nondamaging fracturing fluid that would improve the success of fracture stimulation in the Morrow and Atoka formations. A foamed methanol system was developed to address the high clay content and water sensitivity of these formations. The paper presents the rheological, fluid-loss, and friction properties of the fluid system. Since the introduction of this system, more than 100 successful treatments have been pumped with favorable results. Case histories of both low-pressure and high-pressure zone completions are presented.

Introduction
Conventional fracture-stimulation treatments performed in southeastern New Mexico yielded only a two-fold production increase. In some cases, various factors caused production to decline.

Traditionally, formations consisting of clay are poor candidates for water-based fracturing fluids. The clay's swelling and migrating properties are exacerbated by water contact, nullifying the effects of a stimulation job. Formations that tend to absorb fluids generally respond better to foamed fracturing treatments. However, in clay formations, water-based foams cause the same problems as fluids.

By considering the well's history and extensively testing fracturing fluids, fracture designers identified enough parameters to develop a methanol-based carbon dioxide (CO_2) fracturing foam that accommodated the formation's particular limitations and increased production more than previous stimulation jobs.

A high methanol content and special surfactants allowed a fracturing fluid to increase production 6- to 10-fold in undepleted gas wells that had wellbore damage. Conversely, in areas where wells were assumed to be depleted, but undamaged, 90% of the wells have quadrupled production.

This paper traces the treatment's development, from the wells' prefracturing history to post-fracture production results, with particular attention to the use of methanol in fracture design. The paper also presents laboratory studies, application techniques, and case histories that show how the methanol and surfactant contribute to the fracturing fluid's success in southeast New Mexico.

Field Location and History

The Pitchfork Ranch Field is in southwestern Lea County, in southeastern New Mexico, approximately 110 miles northwest of Midland, Texas. This Delaware basin field has proven to be a prolific producer in the Morrow and Atoka formations, and it has an areal extent exceeding 20 square miles.

The field was discovered in 1982 with a completion in the Morrow "C" sand at a depth of nearly 15,000 ft. The Morrow "C" interval is the field's primary producing interval, generally producing gas with very little water or condensate.

Characteristics of the Morrow Formation

The Morrow formation, a sandstone reservoir, is a series of submarine fan lobes that were fed by channels from the Central Basin platform, which lies 12 miles to the east. Pay thickness ranges from 20 to 70 ft; average porosity is 7%; and permeabilities range from 0.01 to more than 100 md, but are usually less than 5 md.[1]

X-ray diffraction and scanning electron microscope (SEM) studies were conducted on a core from a recently drilled well, and results indicated that the reservoir is primarily clay-rich quartz and calcite sandstones containing moderate amounts of feldspar, dolomite, illite, kaolinite, chlorite, and mixed clay layers of smectite and illite (Table 1).

Because of clay presence, the Morrow formation is easily damaged by water contact: smectite and illite swell on contact with water, and illite and chlorite clays can migrate under adverse conditions. Formation damage results when the swollen and migrated clays reduce the formation's natural permeability.

Stimulation History

The reservoir had an initial bottomhole pressure of approximately 10,000 psig, and during the early life of the field, most of the wells exhibited high flow rates and pressures. If the wells failed to perform as expected, they were generally acidized with a formula consisting of 5.5% hydrochloric acid (HCl), clay stabilizers, iron sequestrants, mutual solvents, and nitrogen, which enhances fluid recovery.

Operators seldom attempted to fracture the Morrow formation because of a poor success record for such treatments. During the past 5 years, before the work in the Pitchfork Ranch field described in this paper, fewer than a dozen fracture treatments had been performed in this formation, and all provided very poor results. Most of these fracture treatments were conducted during the initial completion operations, and the wells generally failed to respond. The attempted workovers were performed on wells producing less than 100 Mcf/D; these treatments failed to improve the wells' performance.

This history of poor fracture treatment performance, coupled with low permeability and the presence of clays, led to the typical industry approach: "If you have a good Morrow well, don't touch it." However, a closer examination of these wells revealed some of the problems operators were experiencing. When the reservoir pressure began to decrease, many of the wells exhibited steep production declines because of their inability to overcome restrictions in and around the wellbore; this inability was caused by inefficient completions.

While the rate declined, liquid loading also became a problem. In many "tight" reservoirs, liquid loading can be very detrimental because the fluids tend to saturate the pore spaces around the wellbore, decreasing the relative permeability to gas.

In the Pitchfork Ranch field, several wells exhibited this tendency. The well described in Case 2 in this paper began a severe decline in 1987. A reservoir pressure of 3,200 psig indicated substantial remaining reserves. The bottomhole pressure was too high to be considered a realistic or acceptable abandonment pressure.

Other recovery methods were sought; the first attempt involved the use of compressors. Initially, this measure helped, but production soon declined to its previous rate, indicating the presence of skin damage. Other wells in the field were showing similar production behaviors, suggesting that they would have abnormally high abandonment pressures.

Stimulation Alternatives for the Morrow Formation

Alternative stimulation techniques were investigated. Even though acid treatments benefited the initial completion by opening all the perforations, they did not adequately improve the formation's permeability to gas. Various fracturing techniques, with a variety of fluids and additives, were analyzed for their possible effects on the formation.

The following characteristics were key concerns for a Morrow fracturing design:

- The reservoir had low permeability.
- The high clay content made water contact potentially damaging.
- The depleted reservoir lacked sufficient energy to unload any induced fluids.
- The reservoir tended to absorb fluids, reducing the relative permeability to gas.
- The industry had an overall poor success history in fracture-treating the Morrow formation in the region.

Properties of Methanol Foam

To address these concerns, designers selected a foamed methanol fracturing fluid that had the following good characteristics:

- low water content
- low surface tension

- good proppant-carrying capacity
- minimal formation damage tendency
- good flowback
- low friction pressure

These characteristics are further documented in other literature.[2,3]

Foamed methanol fracturing fluid consists of a 60-quality, CO_2-foamed methanol solution, which is further described in the following section. The high CO_2 content provides additional energy, improving fluid recovery.

The low friction-pressure of alcohol foams allows them to be pumped at higher injection rates than nonalcohol foams. Friction pressure for methanol is approximately 75% less than the friction pressure for water.[2,4]

The fluid presents a safety risk: methanol is highly volatile, and the added CO_2 brings this volatile substance to high pressures. Among other precautionary measures, a CO_2 blanket is maintained over the blender tub to keep oxygen away from the fluid, reducing the chances of combustion. Because methanol burns without color, a saltwater spray is maintained over the blender tub to indicate any fire.

Lab Studies on Methanol Foam

In laboratory studies, methanol-water mixtures have prevented damage to clay-bearing porous media. For these studies, synthetic porous media packs with permeabilities of 3 to 4 md were prepared, consisting of 50% 100-mesh sand, 40% silica flour, and 10% smectite. Mixtures of fresh water, 20 to 80% methanol, and 2% potassium chloride (KCl) water were flowed through the packs. Subsequent flow of 2% KCl water indicated that permeability was maintained; however, fresh water that was flowed into the pack virtually shut off the permeability.

Determining Methanol Concentration. In these studies, the percentage of methanol in the mixtures could range from 20 to 80%, but we needed to determine the correct percentages of methanol and water for the foam.

To perform properly, the foam must have a sufficiently high methanol concentration, so that the formation's connate water will only slightly dilute the methanol (i.e., water mixture above 20% methanol). However, foams with high methanol concentrations require special considerations.

Foams with a methanol content greater than 50% require special foaming agents called fluorosurfactants. Nitrogen (N_2) foams containing up to 100% methanol can be stabilized with certain fluorosurfactants; carbon dioxide foams, however, cannot be foamed with 100% methanol because CO_2 and methanol are completely miscible. Approximately 5% water must be added to the methanol for a second phase in liquid CO_2, but 20% water in the methanol is required for a stable CO_2 foam.

Viscosity vs. Gas Quality. For foams with a high methanol content, the viscosity increase vs. gas quality is similar to the values for water foams (Figure 1). (Gas quality is defined as the volumetric percentage of gas in the foam.) Figure 1 is typical of both N_2 and CO_2 foams. When gas is added to the methanol liquid phase containing a fluorosurfactant, viscosity begins to increase when the quality reaches 30 to 40%. Higher qualities multiply the base liquid's viscosity.

Methanol-based foams differ from water-based foams because methanol foams are sensitive to breakdown at high shear rates. For the laminar flow shear conditions present in Figure 1, foam structure and viscosity begin to collapse above 70 quality. Higher shear rates begin to degrade the foam at lower quality.

Shear Collapse. Compared to shear-stable water foams, the shear collapse of methanol foams is a result of differences in the texture, or bubble size distribution, of the two foams.[5] For a given equilibrated shear condition, water foams form smaller bubbles (Figure 2), so larger bubbles will collapse first for any given shear condition. Because of the texture effect and to prevent shear collapse of methanol foams, fracture designers have generally run field treatments with approximately 60-quality gas.

Gelling Agent. In field treatments, methanol foams typically contain a gelling agent. For treatments presented in this paper, the gelling agent was a high molar substitution hydroxypropyl guar (HPG). The higher-than-normal molar substitution on the guar enhances the polymer's solubility in methanol.

Fracture-Treatment Planning

Step-rate tests, minifracs, and pressure transient testing were performed before each of these early fracture treatments in the Pitchfork Ranch field. The tests (1) obtained information about the reservoir properties of the Morrow formation and the properties of the methanol foam system, and (2) measured the reliability of the fracture design. The results of these wellsite tests indicated that the friction pressure and viscosity of the methanol foam system were lower than the values for a water-based foam system.

Original fracture designs were computer-modeled with Khristianovich and Zheltov fracture geometry[6-8] and fluid-loss coefficient (C_{eff}) from minifrac analysis. Currently, designs are done with the FracPro® 3D fracture simulator, and proprietary foam fluid rheology and friction correlations. The designs allowed for a tip-screenout at the very end of the treatment; we used the field results to adjust the C_{eff} values. C_{eff} values obtained in this way are shown in Figure 3, which is plotted according to the reservoir permeability of the associated wells. Friction pressures, also determined from field data, are shown in Figure 4. For comparison, predicted friction-loss values for a water-based CO_2 foam fluid are shown in Figure 5. Based strictly on the design developed from the field data, methanol foam treatments have been pumped consistently, on schedule, at the predicted rates and pressures.

The base gel used for these fracturing treatments was made up with 60% methanol, 40% water-based fluid, and the additives listed in Table 2.

The recommended fracturing treatment requires 40,000 gal of 60-quality methanol foam carrying 35,000 lb of 20/40-mesh proppant in a single stage. The fracture treatment is performed down 2 $^7/_8$-in. tubing at 20 bbl/min with an anticipated BHTP of 10,500 psi. The surface treating pressures are approximately 9,500 psig at rates of 18 bbl/min. The fracture-treatment data for Case 1 is given in Table 2 and is typical of treatments in the Pitchfork Ranch field.

Figure 6 is taken from a real-time treatment log of a typical job in this field. Parameters include tubing pressure, slurry rate, CO_2 rate, and proppant concentration.

Case Histories

Four wells from the Pitchfork Ranch field are examples of typical production from the Morrow formation. The wells showed post-fracture production increases ranging from 1.5- to 35-fold (Table 3). Typical treatment parameters for the four case history example wells are shown in Table 2, which details the fracturing treatment data for Case 1. The production history from Case 3 is typical of production from these wells (Figure 7). Before fracturing, production was quite low (33 Mcf/D); after fracturing, production increased and held steady at a rate of 1,180 Mcf/D (except for a 1-month shut-in period).

Summary

Because of its rock properties and reservoir characteristics, the Morrow formation of southeast New Mexico was rarely stimulated successfully.

In consideration of the Morrow formation's characteristics, a specialized fracturing fluid was developed, consisting of a methanol-based fluid foamed with CO_2. Several case histories show that the Morrow C interval can be fracture-treated with this fracturing fluid, resulting in significant production increases.

Acknowledgments

The authors thank Halliburton Energy Services, Inc. and Enron Oil & Gas Co. for permission to publish this paper.

References

1. Simon, David E. and Underwood, P.: "Morrow Stimulation in Southeast New Mexico," paper SPE 6375 presented at the SPE-AIME 1977 Permian Basin Oil & Gas Recovery Conference, Midland, Texas, Mar. 10-11.
2. Harris, P.C.: "Application of Foam Fluids to Minimize Damage During Fracturing," paper SPE 22394 presented at the 1992 International Meeting of Petroleum Engineering, Beijing, China, Mar. 24-27.
3. "Surface Tension of Methyl Alcohol in Water," *Handbook of Chemistry & Physics*, R.C. Weast (ed.), Boca Raton, Fla. (1981) F-44.
4. Gras, Ernst H.: "Alcohol Comes on Strong as a Fracturing Fluid," *Drilling-DCW* (May 1973).
5. Harris, P.C.: "Effects of Texture on Rheology of Foam Fracturing Fluids," *SPEJ* (Aug. 1989) 249-257.
6. Khristianovich, S.A. and Zheltov, Y.P.: "Formation of Vertical Fractures by Means of a Highly Viscous Liquid," Oric, Fourth World Petroleum Cong., Rome (1955) Sec. 11/T.O.P., paper 3,579.
7. Daneshy, A.A.: "On the Design of Vertical Hydraulic Fractures," *JPT* (Jan. 1973) 83-97.
8. Daneshy, A.A.: "Opening of a Pressurized Fracture in an Elastic Medium," *JPT* (Jan. 1978) 132-140.

Table 1 - X-Ray Diffraction Analysis of Morrow Formation Cores

Rock Type (% of total)	Depth (ft)			
	14,610 to 14,620	14,700 to 14,708	14,830 to 14,836	14,836 to 14,841
Quartz	50 to 65	50 to 65	45 to 55	40 to 50
Feldspars	0.5 to 2	5 to 10	0.5 to 2	0.5 to 2
Calcite	10 to 15	5 to 10	20 to 30	15 to 20
Dolomite	0.5 to 2	0.5 to 2	0.5 to 2	0.5 to 2
Kaolinite	2 to 5	—	0.5 to 2	—
Illite	2 to 5	2 to 5	2 to 5	0.5 to 2
Chlorite	2 to 5	2 to 5	2 to 5	—
Mixed clay layer[a]	5 to 10	5 to 10	5 to 10	10 to 20

[a]Smectite and illite

Table 2 - Fracturing Treatment Data for Case 1

Identification	
Well Type:	gas
Formation	Morrow C
Location:	Pitchfork Ranch Field, New Mexico
Well Information	
Depth:	15,206 ft
Casing:	7 in. × 26 lb/ft
Liner:	4 1/2 in. × 13.5 lb/ft
Tubing at 12,967 ft:	2 7/8 in. × 7.9 lb/ft
Packer Depth:	12,967 ft
Perforations:	14,894 to 14,948 ft
Max. Allowable Surface Treating Pressure:	12,000 psi
Fracturing Gradient:	0.66 psi/ft
BHSP:	approx. 3,000 psi
BHST:	200°F
Spacing:	360 acres
Formation Permeability:	0.23 md
Formation Porosity:	6%
Net Height of Interval:	40 ft
Gross Height of Interval:	40 ft

Pump Schedule

Volume (gal)	Fluid Type	Proppant Type	Concentration (lb/gal)
8,000	60% methanol foam prepad at 10 bbl/min		
Shut down for 15 minutes			
22,000	60% methanol foam prepad at 20 bbl/min		
2,000	60% methanol foam	20/40-mesh proppant	0.5
4,000	60% methanol foam	20/40-mesh proppant	1
6,000	60% methanol foam	20/40-mesh proppant	2
6,000	60% methanol foam	20/40-mesh proppant	3
4,000	60% methanol foam as flush		

Fluid Composition

Methanol foam base gel

Total: 25,900 gal

Methanol: 16,500 gal

Water: 10,400 gal

Additives per 1,000 gal

1 gal of surfactant

50 lb of gelling agent

2 lb of pH buffer

4 gal of foaming agent

65 lb of KCl for clay control

1 lb of breaker

Table 3 - Production Results Before and After Fracturing

Case Number	Gas Production (Mcf/D)		Flowing Tubing Pressure (psig)	
	Before	After	Before	After
1	960	3,400	310	1,025
2	450	2,403	210	490
3	33	1,180	940	380
4	1,990	3,000	500	3,300

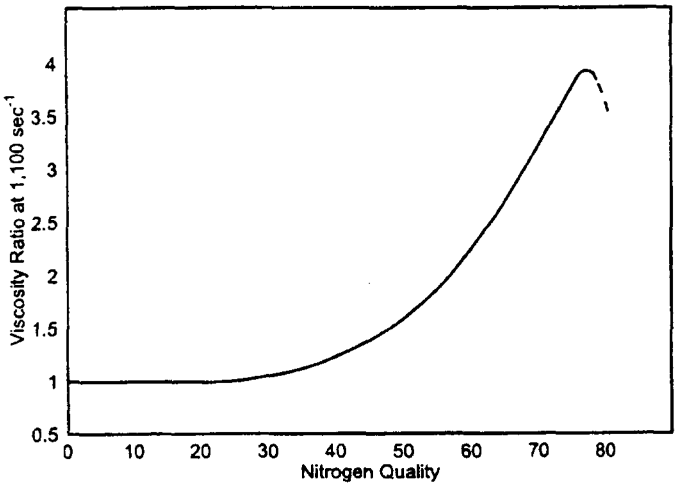

Figure 1 - Viscosity of Methanol Foam Consisting of 90:10 Methanol:Water, 0.3% Fluorosurfactant

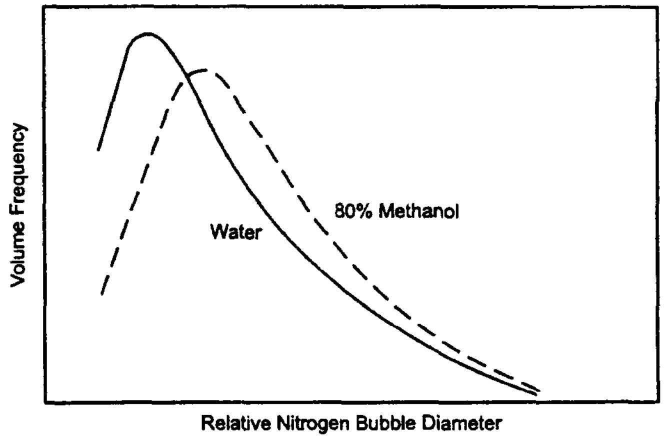

Figure 2 - Texture of Water and Methanol Foams The foams were equilibrated at 1,100 sec^{-1}.

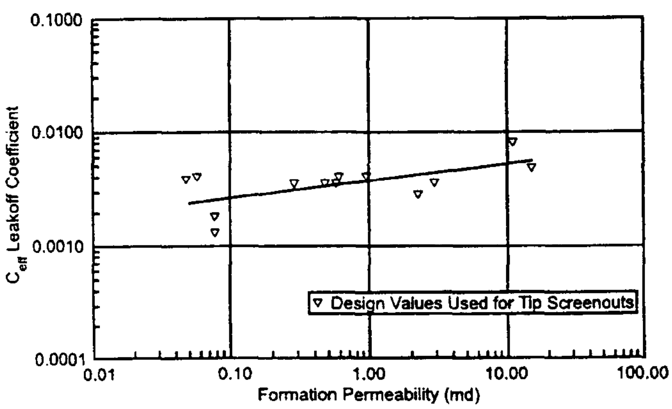

Figure 3 - C_{eff} for Foam System, Field-Derived Values 50lbm/Mgal Base Gel with 60% MeOH, 60-Quality CO_2 Foam

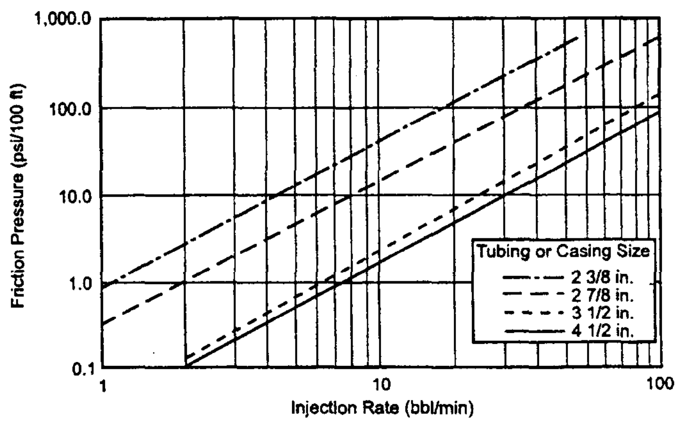

Figure 4 - Friction Pressures for Foam System, Field-Derived Values 50 lbm/Mgal Base Gel with 60% MeOH, 60-Quality CO_2 Foam

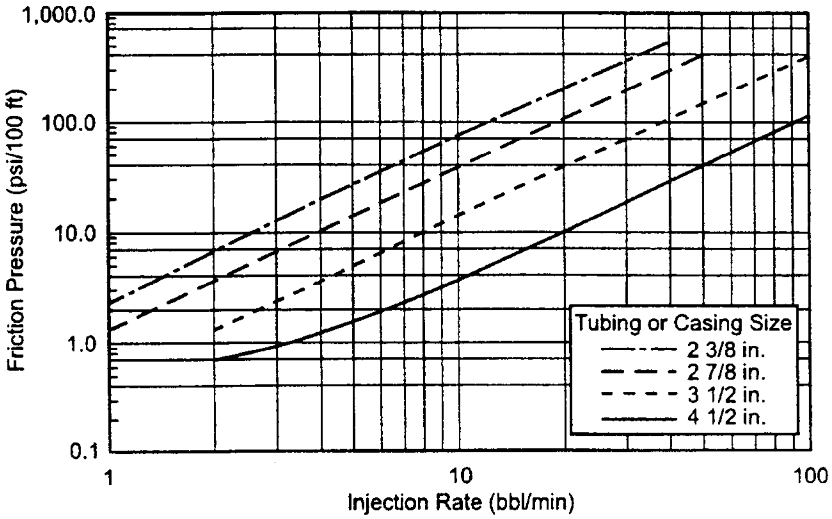

Figure 5 - CO_2 Friction Pressures for Water-Based, 60-Quality, 50 lbm/Mgal Foam System

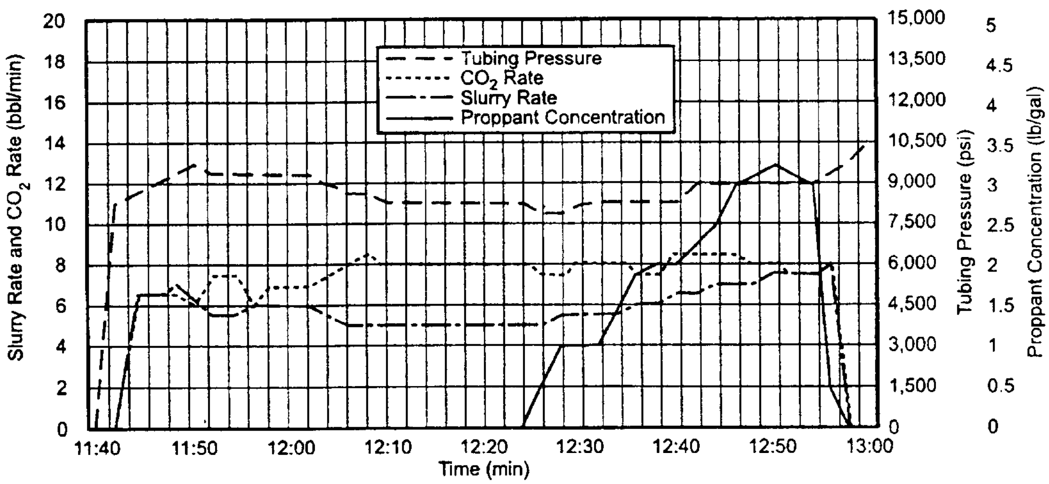

Figure 6 - Real-Time Treatment Log

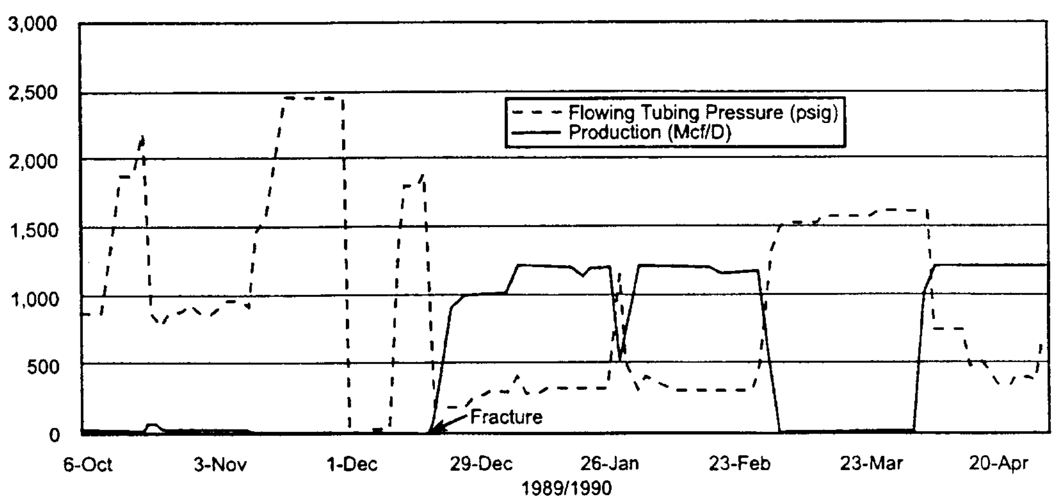

Figure 7 - Case 3 Production History