HIGH-PERFORMANCE FRACTURE FLUID OUTPERFORMS CONVENTIONAL LOW-POLYMER BORATES

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ABSTRACT

A High-Performance Fracturing Fluid (HPF) has led to a step change in the completion process of the San-Andres reservoir in Andrews County, Texas. Recent development in fluid technology has resulted in the introduction of a unique fracturing fluid that is less damaging to the formation, has excellent proppant transportability, and requires no breakers. Despite very robust and stable rheological properties during pumping, HPF returns to its original viscosity shortly after closure with no internal breakers. The unique properties of this fluid will be discussed along with case history information.

Additionally, the paper will attempt to explain well performance compared to wells in the same field that were fractured with conventional low-polymer loading borates. The distinctive properties of this fluid will be presented, along with a discussion of the retained conductivity of the fracture. Case histories of this field show better return on investment using this fluid.

INTRODUCTION

The field of interest is the Means San-Andres Field in Andrews County, approximately 10 miles northwest of Andrews, Texas. The San-Andres reservoir is an oil-producing dolomite ranging from approximately 4,600 to 4,700 ft with an average porosity of 10%, an average permeability of 0.05 to 0.5 mD, and a bottomhole static temperature (BHST) of 105°F. The drive mechanism of the San-Andres is a weak water drive and gas expansion of undersaturated oil.

Fracture stimulation of the San-Andres reservoir has evolved from pumping inefficient oil-based fluids, which provided very poor proppant-transport properties, to using borate-crosslinked polymer systems, which are considered to have efficient leakoff control and excellent proppant-transport properties. For several years, a low-polymer borate system has been used to fracture stimulate the San-Andres. The typical job size consists of 70,000 gal of a low-polymer borate fluid carrying 140,000 lb of 16/30-mesh white sand pumped down 5.5-in. casing with an average rate of 35 bbl/min and a maximum sand concentration of 6 lb/gal. This job design was the result of several step changes that evolved from attempts to optimize the frac design and place a higher concentration of proppant in the fracture. Average production rates in the San-Andres reservoir range from 40 to 60 BOPD, plus 250 BWPD with a fairly rapid decline.

CHANGE IN PROCESS

With the application of new viscoelastic fluid technology, a very robust HPF has been developed that can dramatically reduce the detrimental conductivity-damaging properties of conventional polymer-based fracturing fluids. This HPF has polymer-like fluid rheology and fluid-loss control even though no high-molecular-weight polymer chains are present. Additionally, the HPF can delink back to its initial low viscosity without the use of chemical breakers.

Short molecular units that can link and delink create a transitory pseudopolymer **(Figure 1).** These pseudopolymer chains can further link together to build a fluid with a high level of 3D stability **(Figure 2).** The transitory nature of the pseudopolymer allows the fluid to behave like a polymer, but chemicals are not required to break the polymer chain. The strength of the crosslink is determined by the base fluid pH and the specific metal ion used as a crosslinking agent. The natural pH of the formation is sufficient to delink the fracturing fluid; therefore, when the job is complete and pumping has stopped, the HPF will delink back to the short molecular units, allowing for efficient clean-up and minimal damage to the proppant bed.

The fluid properties of the HPF system are so robust that fluid design changes, such as reduced pad volumes, lower rates, and increased sand concentrations, can be incorporated into the frac design. The San-Andres reservoir was considered a prime candidate for fracturing with HPF because of the HPF's robust fluid properties and ability to delink and clean up with minimal damage to the formation and proppant bed. The selected wells had produced sufficiently with the current frac design using a low-polymer borate system, but changing to the HPF system was considered feasible because it could potentially increase the proppant concentration placed in the fracture and increase the fracture conductivity by minimizing the damage incurred from the frac fluid.

FRACTURE CONDUCTIVITY

Damage to fracture conductivity from gel filter cake and unbroken gel has been a persistent industry problem. Attempts to alleviate the damage have included using very aggressive breaker systems, gel filter-cake removal procedures, and new chemical systems developed to improve or enhance fracture-fluid performance. HPF has been tested with proppant packs at reservoir conditions to determine fracture conductivity.

All fluid systems used for hydraulic fracturing affect the conductivity of a proppant pack. The comparison of the reduction in the conductivity to that of the proppant pack with no fluid present is the fluid system index. Specifically, the fluid system index is the value (expressed as a decimal fraction) determined by dividing the conductivity of the proppant pack, including the effects of the fluid system, by the baseline conductivity of the dry proppant bed. Conductivity values and corresponding fluid system index values for the HPF with no breakers added are shown in **Table 1.** The same data for a conventional low-polymer borate system with a typical oxidizing breaker is presented in **Table 2.**

Table 3 shows data for a conventional low-polymer borate system with a highly aggressive breaker package, including an oxidizing breaker and a catalyst. The aggressive breaker package system shows improved performance over the conventional breaker package, but the performance of the HPF system is not dependent on breakers. Aggressive breaker systems used with a crosslinked polymer gel can help remove gel filter cake and help break the gel, but the residue created from breaking the crosslinked polymer can cause a considerable amount of damage to the fracture conductivity. When the HPF delinks and reverts back to short-chain molecules, the fluid can flow back through the proppant bed with minimal damage to fracture conductivity. As a result, the HPF system provides an increased effective propped length compared to that of low-polymer borate systems, which translates into improved production. **Figure 3** shows a comparison of a low-polymer borate system broken with an enzyme breaker and the HPF system delinked by dropping the pH.

FLUID LOSS

Laboratory testing shows that, through the development of gel filter cake, the HPF system is very efficient. **Table 4** compares fluid-loss coefficients for the HPF system and conventional low-polymer borate systems. **Figure 4** shows dynamic fluid-loss curves for three permeability core samples. The comparison illustrates that the HPF system can provide fluid-loss coefficients comparable to conventional fluid systems, indicating that the HPF system does not compromise the fluid efficiency of a fracturing treatment. The HPF system is highly efficient and does not begin to delink until pumping has stopped and positive pressure from leakoff has dissipated.

CASE HISTORY

Two wells were chosen for comparison of the HPF system to the conventional low-polymer borate system: (1) a newly drilled completion to be fracture stimulated with HPF, and (2) a direct offset well previously stimulated using the conventional low-polymer borate system. The location of the comparison wells can be seen in **Figures 5** and **6.**

The two wells are similar. The low-polymer borate well (Well No. 1) has an elevation of 3,189 ft, an average porosity of 9%, a water saturation of 27.1%, and a total net pay interval of 134.5 ft. The HPF well (Well No. 2) has an elevation of 3,193 ft, an average porosity of 9%, a water saturation of 32.1%, and a total net pay interval of *85.5* ft. A comparison of the two wells can be seen on the log segments in **Figure 7.**

The frac design of Well No. 1 consisted of 70,000 gal of low-polymer borate carrying 143,000 lb of 16/30-mesh white sand pumped at 35 bbl/min with a maximum sand concentration of 6 lb/gal. The job was pumped to completion with an average treating pressure of 2,200 psi. With the conventional low-polymer borate fluids being used, pad volumes had been increased up to approximately 40% in an attempt to place more and higher concentrations of proppant in the formation. Generally, a maximum concentration of 6 lb/gal of sand was achieved with the low-polymer borate fluid, and often, the well was on the verge of screening out at the end of the scheduled treatment.

The frac design on Well No. 2 consisted of 30,500 gal of HPF carrying 143,000 lb of 16/30-mesh white sand pumped at 35 bbllmin with a maximum sand concentration of 10 lb/gal. The total fluid volume for the job was reduced by 50%, the pad volume was reduced to 33%, and the sand concentration was increased to 10 lb/gal. With these changes, the fracture treatment using the HPF system was pumped at an average treatment pressure 2,700 psi with no problems. The surface treating pressure increased because the friction properties of the HPF system are higher than those of the low-polymer borate.

Production data from both wells can be seen in **Figure 8.** The initial production rate of Well No. 2 was a little higher than that of Well No. 1 with a significant difference in the production decline. After approximately 30 days, Well No. 2 had a fairly sustained production rate of 170 BOPD, whereas Well No. 1 continued to decline. Well No. 2 started to decline after 100 days of production but continued to produce at a considerably higher rate than Well No. 1.

A cumulative production revenue comparison of the two wells is shown in **Figure 9.** Well No. 2 had a cumulative production of 38,700 bbl of oil compared to 26,400 bbl for Well No. 1. This difference is equivalent to a created value increase of over $189,000 for the HPF fractured well, based on an oil price of $18 per barrel.

CONCLUSIONS

Application of an advanced viscoelastic fracturing fluid has resulted in a very positive impact on the production of the San-Andres formation in Andrews County. The highly robust fluid properties of the HPF system enabled a more aggressive proppant schedule to be successfully placed in the well with no problems. The increased sand concentration placed in the proppant pack, along with the clean nature of the delinked fluid and the short molecular units of the base fluid, allow for higher fracture conductivity, which directly correlates to a longer effective propped frac length. The fracture conductivity and effective propped length led to an increase in production of the HPF fractured well.

REFERENCES

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2. Parker, M.A. and McDaniel, B.W.: "Fracturing Treatment Design Improved by Conductivity Measurements Under In-Situ Conditions," paper SPE 16901 presented at the 1987 Annual Technical Conference and Exhibition, Dallas, Texas, 27-30 September.
3. McGowen, J.M. and Vitthal, S.: "Fracturing-Fluid Leakoff under Dynamic Conditions Part 1: Development of a Realistic Laboratory Testing Procedure," paper SPE 36492 presented at the 1996 SPE Annual Technical Conference and Exhibition, Denver, Colorado, 6-9 October.
4. Voneiff, G.W., Robinson, B.M., and Holditch, S.A.: "The Effects of Unbroken Fracture Fluid on Gas Well Performance," paper SPE 26664 presented at the 1993 Annual Technical Conference and Exhibition, Houston, Texas, 3-6 October.

Table 1
API Cell Conductivity Values
Fluid A with 2-lb/ft² 20/40-Mesh Ottawa Sand

Closure Stress (psi)	Conductivity (mD-ft)	Fluid System Index
2.000	2744	0.65
4.000	1705	0.74
6.000	540	0.62

Table 2
API Cell Conductivity Values
Fluid B with Oxidizing Breaker at 180°F with 2-lb/ft² 20/40-Mesh Ottawa Sand

Closure Stress (psi)	Conductivity (mD-ft)	Fluid System Index
2,000	674	0.16
4,000	390	0.17
6,000	209	0.24

Table 3
API Cell Conductivity Values
Fluid C with Highly Activated Oxidizing Breaker
at 180°F with 2-lb/ft^2 20/40-Mesh Ottawa Sand

Closure Stress (psi)	Conductivity (mD-ft)	Fluid System Index
2,000	2526	0.60
4,000	1011	0.44
6.000	488	0.56

Table 4
Dynamic Fluid-Loss Coefficients
HPF at 180°F with Ohio Sandstone Core Wafers (0.1 to 0.3 mD)

Fluid	Cw (ft/min $^{0.5}$)	Spurt (gal/ft^2)
Fluid A: HPF system 11 cP at room temperature	0.0019	0.003
Fluid B: conventional fluid 25 lb/Mgal with 0.25-lb breaker (guar/borate with oxidizing breaker)	0.0029	*0*
Fluid C: conventional fluid 25 lb/Mgal with 15-lb high activity catalyzed breaker package (guar/borate, with activated oxidizing breaker)	0.0036	0.003

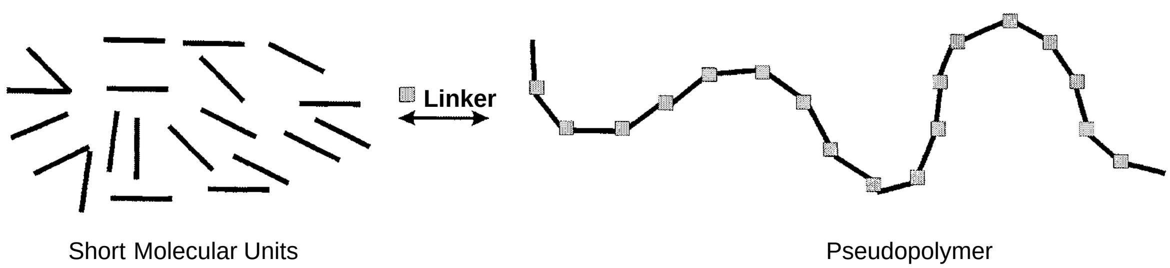


Figure 1–A transient pseudopolymer can be formed under the correct environmental conditions by linking short molecular units. This pseudopolymer exhibits rheology and fluid-loss properties similar to the common guar-based polymers. This reaction is easily reversible to the starting short molecular units by controlling pH.

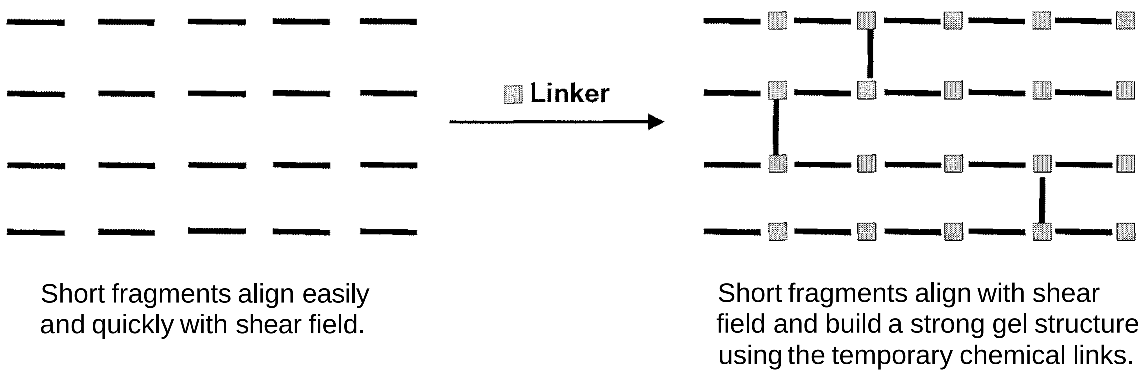


Figure 2–In a shear field, the short molecular fragments quickly align with the field. Affecting the linking reaction in this shear regime leads to a highly organized, 3D network that has a high level of elasticity. Because of the dynamic nature of the linking reaction, this structure continuously reorganized to adjust to the shear field.

Low-Polymer Fluid
Enzyme Break

HPF
Delinked by pH

Figure 3–Broken Fluid Comparison

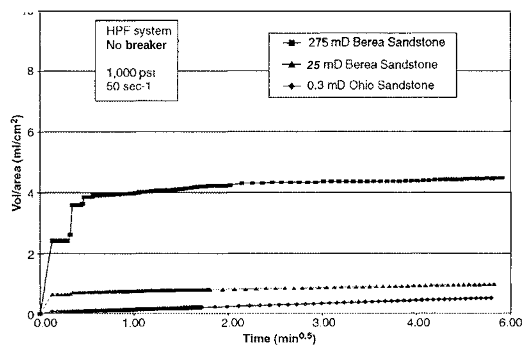


Figure 4–HPF Dynamic Fluid-loss Comparison

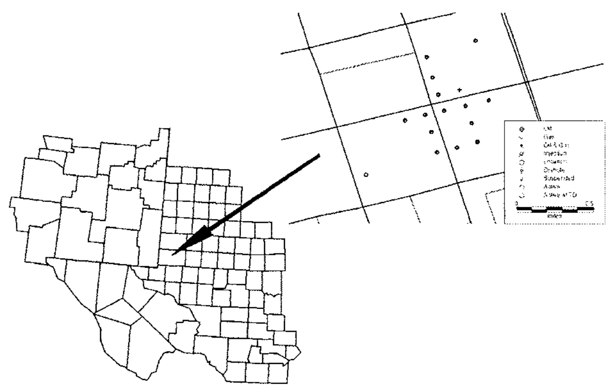


Figure 5–Location of Comparison Wells

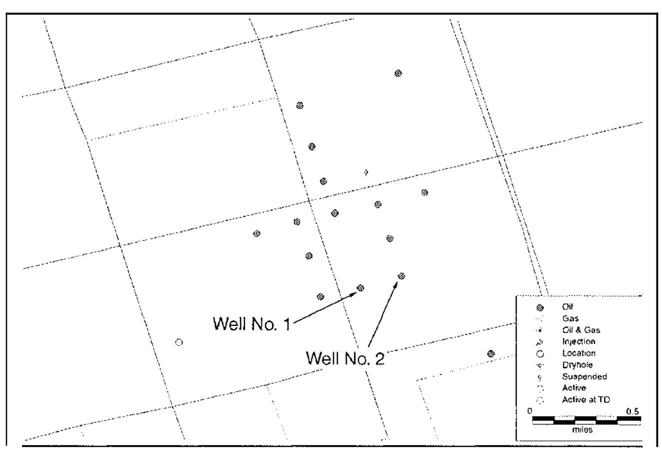
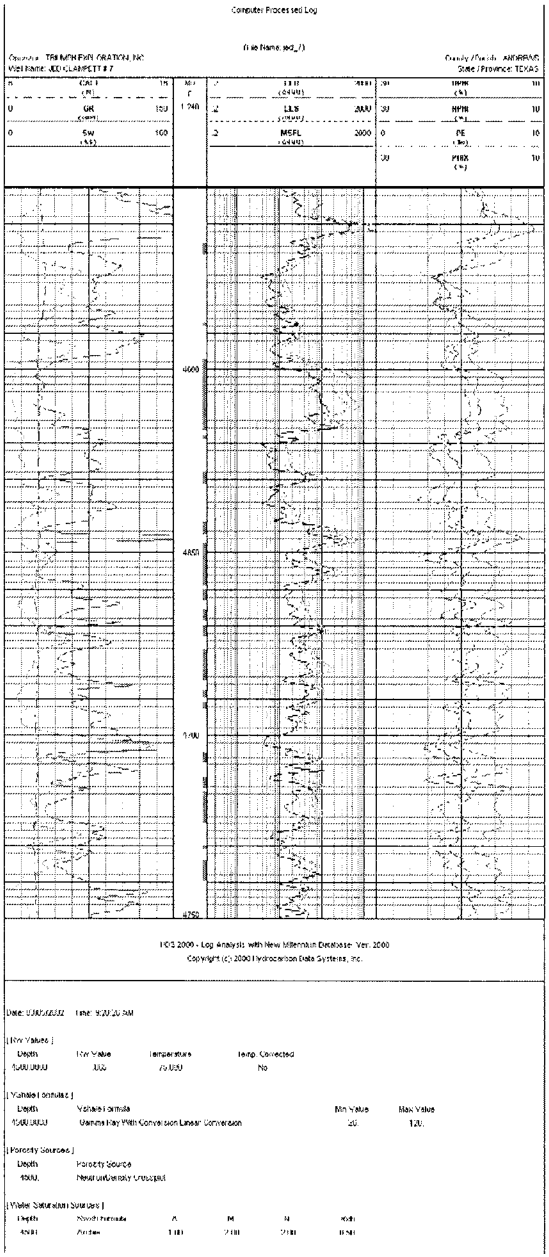


Figure 6–Comparison of Well Locations - Well No. 1 is the low-polymer borate system; Well No. 2 is the HPF system.

HPF Well



Low-Polymer Well

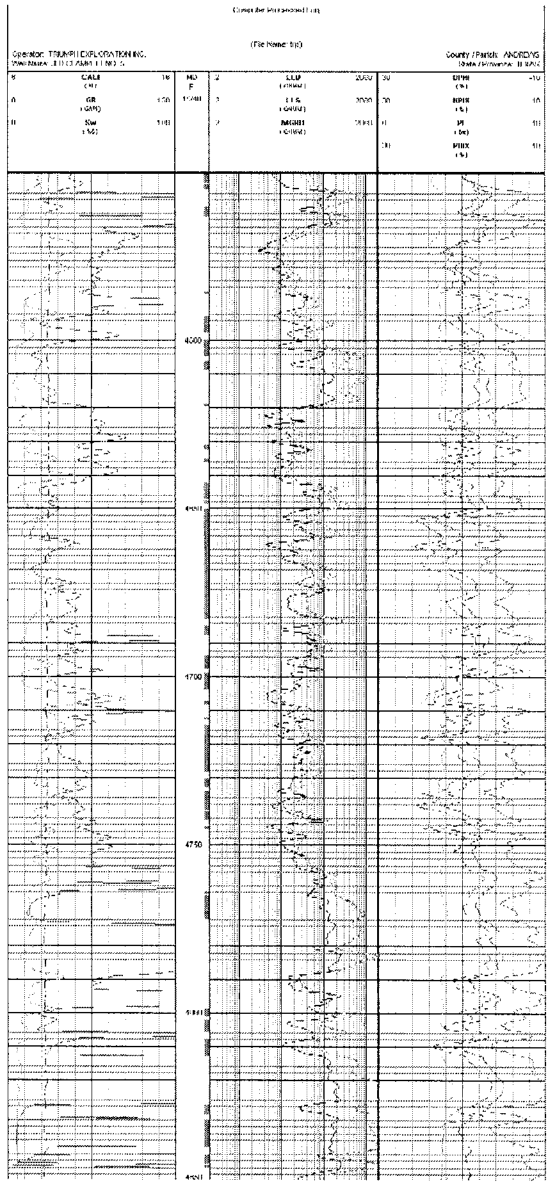


Figure 7 - Comparison of Well Log Segments

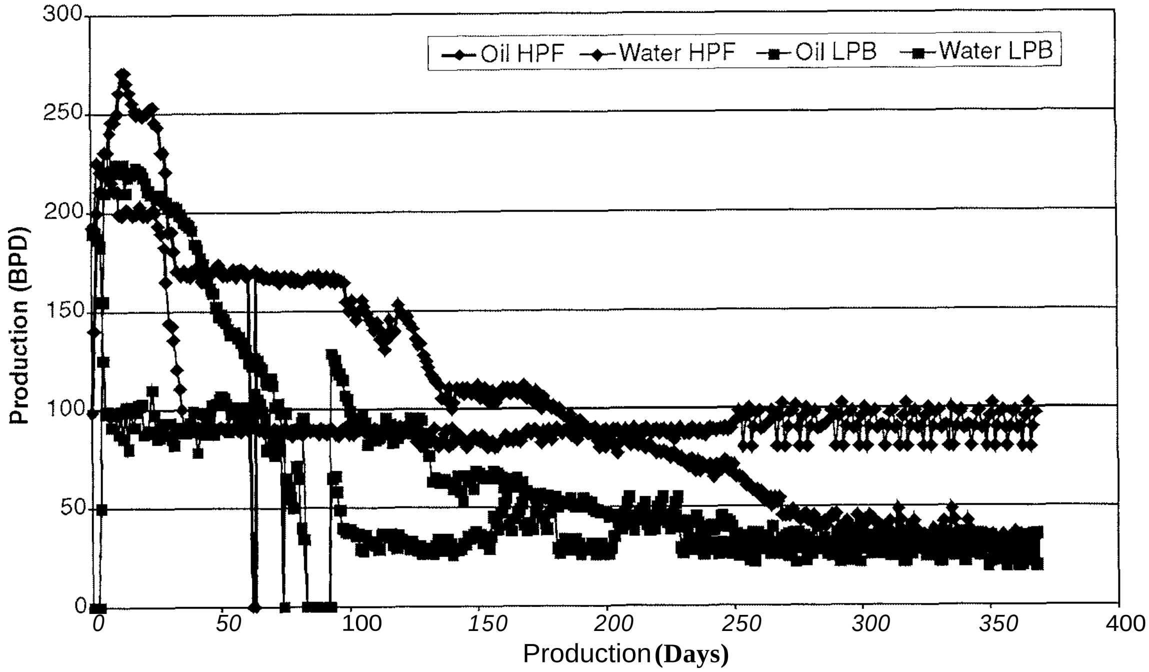


Figure 8 - Production Rate Comparison

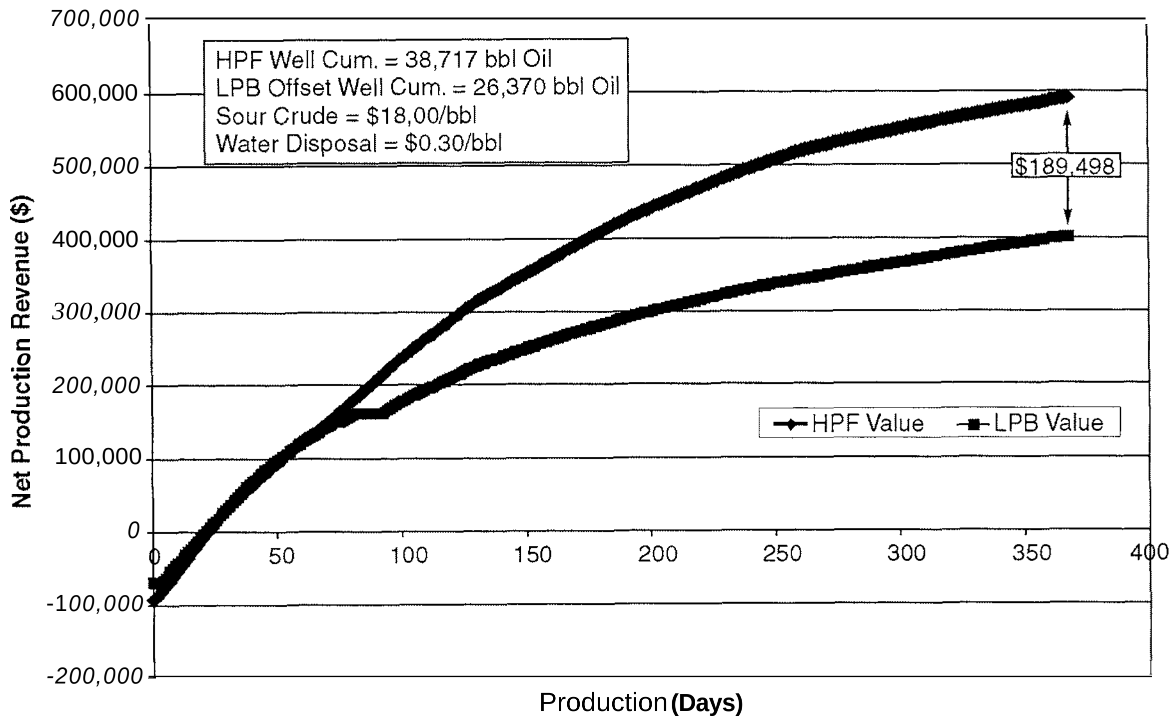


Figure 9 - Cumulative Net Production Revenue Comparison