ROCKY MOUNTAIN OILFIELD TESTING CENTER

PROJECT TEST RESULTS

MICROBIAL PRODUCTION STIMULATION

MARCH 31, 1998

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ROCKY MOUNTAIN OILFIELD TESTING CENTER

Microbial Production Stimulation

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Executive Summary

The sulfates in oilfield waters are often reduced to form sulfides of iron and hydrogen. This process raises safety concerns with higher corrosion rates in production systems and the threat of poisonous hydrogen sulfide gas releases. Iron combines with hydrogen sulfide and forms iron sulfide, an acid soluble scale. It plugs up fluid flow paths. The iron loss from production tubulars causes a corrosion concern. This process increases the operating cost of the well, 'increasing the economic limit of production, and decreasing the recoverable reserves.

It is now well known that nutrients can be introduced into reservoir ecosystems to stimulate beneficial indigenous microorganisms. The introduction of nitrate salts as a nutrient to the denitrifying bacteria (DNB) population causes them to flourish and metabolize the sulfides out of the system, producing by-products commonly used as agents for 'unproved oil recovery.

Volatile fatty acids (VFA), such as acetate, butyrate, formate, lactate and propionate, play a key role in the microecology of petroleum reservoirs. They act as a carbon source for microbial action. The DNB's are more voracious competitors than the sulfate reducing bacteria (SRB's) for the VFA in a given environment. In the presence of nitrate, the DNB become dominant, and depleted the VFA, and drastically decreased the sulfate reduction process. This process was successfully demonstrated at RMOTC in a previous test.

As the DNB populations metabolize the sulfates, flow paths in the reservoir should be reopened to production, and increases in production rates, and recoverable reserves should result from the treatments. The reduction and/or elimination of H2S from the production system will reduce corrosion rates and maintenance costs. Since the Bio-Competitive Exclusion process (BCX) cleans up the sulfides in a system, it reduces its potential toxicity level.

The objective of this test on RMOTC Well 63-3SX10 was to compare the effectiveness of small weekly treatments with a large, once per month treatment. This well was chosen since it had a stable background production rate, a significant level of H2S in the production stream, and a stable reservoir management plan. The well was treated down the casing annulus once per month with a nutrient solution from October 1, 1997 through March 2, 1998. The treatment ws followed by a short shut-in period.

Using the production data from May 1997 through September 1997 as a baseline, average oil production rates increased 7% over baseline while water production rates decreased 7% from baseline. Water oil ratio decreased 15% during the treatment period. H2S concentration decreased 43% from the average concentration observed during the six months prior to the treatment period.

Considering the cost of the larger treatments and the pumping equipment required to administer the treatments, the treatments used in this test were not as economic as the treatments used in the previous test, where one gallon of solution was dumped down the backside of the well once per week. Additionally, the H2S suppression was not as effective as in the smaller more frequent treatments. This treatment did, however, show a clear increase in oil production rates. The economics and effectiveness of treatments will vary from application to application, and no generalizations should be made on these results unless they can be confirmed with follow-on testing under different conditions.

Problem Statement

Sour Production

Some petroleum reserves are associated with sulfur deposits. The sulfates in oilfield waters are often reduced to form sulfides of iron and hydrogen. The sulfides may be produced biogenically or inorganically. Sulfur is then associated with both the liquid and gaseous phase of petroleum production and causes the production to be "sour" production. Sour production brings lower prices in the marketplace because it is more expensive to refine. It also raises safety concerns with higher corrosion rates in production systems and the threat of poisonous hydrogen sulfide gas releases.

Corrosion is a threat to iron 'in the downhole and surface production equipment. Iron combines with hydrogen sulfide and forms iron sulfide, an acid soluble scale. Iron sulfide often starts to form in the reservoir in flow paths, impeding the flow of reservoir fluids, reducing oil and gas production rates and ultimate recovery. Once 'in the tubulars, the hydrogen sulfide causes embrittlement of the steel, and drastically reduces the effective life of wellbore and surface equipment. This increases the operating cost of the well, increasing the economic limit of production, decreasing the recoverable reserves.

Deadly hydrogen sulfide gas also poses a serious safety threat to workers. Toxic in levels as low as 40 PPM, H2S gas increases the operating cost and risk of any work done on the wells and surface equipment. Sophisticated detection systems are stringently required by law when working in H2S areas. Crews must also be trained in the use of self contained breathing systems and rescue procedures.

Bypassed Oil

The recovery of oil from petroleum reservoirs depends on many factors. One of the important ones is the interfacial tension between the reservoir rock, the oil trying to flow through the rock pores, and the fluid wetting the rock face. Some of these forces can be reduced by chemical surfactants, and alcohols. Water pushing oil through the pores can be aided by polymers. These chemicals are only used sparingly due to the cost of such operations. However, many times these improved recovery agents can be produced biologically for a fraction of the cost.

Problem Solution

Concept

The classical interpretation of microbial enhanced oil recovery (MEOR) is to introduce a microorganism along with a food source to effect a positive change 'in the recovery mechanism of an oil reservoir. A common treatment is to clean up paraffin problems in producing wells. More sophisticated processes take advantage of the microbe's ability to produce surfactants, acids, alcohols, and polymers to improve oil recovery. In the Bio-Competitive Exclusion process (BCX), bacteria already existing in the reservoir are stimulated to effect favorable changes in the production stream.

It is now well known that nutrients can be introduced into reservoir ecosystems to stimulate indigenous microorganisms. This commonly occurs when reservoirs are flooded with water containing significant sulfates. This sulfate influx stimulates the indigenous sulfate reducing bacteria (SRB) population which metabolize the sulfate into hydrogen sulfide gas. The hydrogen sulfide then reacts with metallic compounds such as iron to form iron sulfide scale In a similar

manner, the introduction of nitrate salts as a nutrient to the denitrifying bacteria (DNB) population causes them to flourish and metabolize the sulfides out of the system, producing by-products commonly used as agents for improved oil recovery.

Hitzman and Sperl have recently discovered that volatile fatty acids (VFA), such as acetate, butyrate, formate, lactate and propionate, play a key role in the microecology of petroleum reservoirs. This is an important step in understanding reservoir Microecology and effecting positive change using the biological system.

Volatile fatty acids have been found in many petroleum reservoirs. They act as a carbon source for microbial action. They are generally metabolized by sulfate reducing bacteria, such as *Desulfovibrio desulfuricans,* generating H2S gas as a by-product. However, as Hitzman and Sperl reported, adding nitrate to waters containing VFA stimulates the growth of denitrifying bacteria, such as *Thiobacillus denitrificans*. These DNB are more voracious competitors than the SRB's for the VFA in a given environment.

The process of H2S elimination has been successfully tested in core floods and was also reported by Hitzman and Sperl. Six-inch Berea cores, with permeabilities of approximately 400 mD, were flooded both in the presence and absence of nitrates in an anaerobic environment. In the absence of nitrate, SRB concentration increased to 10' colonies per milliliter and sulfate concentration reduced to 0. Sulfide concentration increased, while propionate was totally consumed and acetate was decreased. In the presence of nitrate, the DNB became dominant, and depleted the VFA, and drastically decreased the sulfate reduction process.

This process was successfully demonstrated at RMOTC in a previous test. In some cases total suppression of H2S was attained. The treatment is administered by mixing up a nutrient solution in a small chemical truck and pumping the nutrient solution down the casing annulus of a rod-pumped well. Treatment parameters such as frequency, volume, and shut-in time can be varied to affect treatment results. The treatments have the advantage of being simple, economical, safe, and environmentally friendly.

Benefits

Production Increase

In theory, as the DNB populations metabolize the sulfates, flow paths in the reservoir should be reopened to production, and increases in production rates, and recoverable reserves should result from the treatments. The goal of this test was to prove the theory under actual field operating conditions and quantify the production increases potentially attainable. In previous tests, indications were that measurable production increases were possible.

Cost Savings

The reduction and/or elimination of H2S from the production system will reduce corrosion rates. This will result in reduced maintenance costs. The reduced maintenance costs will come from downhole equipment as well, since the fluid coming into the wellbore is being processed. Reduction in maintenance costs will also be apparent in the surface facilities.

Formation Damage Prevention

If the treatments are large, deep penetration into the formation will not only clean up existing damage, but will prevent further deposition of iron sulfide. The DNB's will metabolize the dissolved sulfide out of the aqueous phase preferentially. As this concentration is reduced, gaseous H2S will partition into the aqueous phase to attempt to restore equilibrium, reducing the concentration in the gaseous phase. When all of this sulfide is consumed, the DNB will begin to act on the solid phase sulfides, such as iron sulfide scale. Once the solid sulfide is consumed, any dissolved or gaseous sulfides, will be quickly consumed, unable to react with iron in the formation and form additional scale.

Safety

Since the Bio-Competitive Exclusion process (BCX) cleans up the sulfides in a system, it reduces its toxicity level. This makes it safer for rig and maintenance crews to work on the well. It also reduces the incidence rates for unscheduled releases of produced fluids.

Test Design

Test Objectives

The objective of the test on well 63-3SX10 was to compare the effectiveness of small weekly treatments with a large, once per month treatment. Weekly treatments have been very successful in the previous test that was conducted. The effect on effectiveness and economics of a major treatment on a less frequent schedule was unknown.

Well Selection

In order to get a valid, long term test on a well, a suitable candidate well had to be selected. This well was expected to have a stable background production rate, have a significant level of H2S in the production stream, and have a stable reservoir management plan. GMT and RMOTC engineering technicians selected well 63-3SX10. This well had been part of the previous GMT test project that examined the effectiveness of the treatments in reducing H2S concentrations in the produced fluids.

Well Equipment Description

A wellbore schematic for Well 63 -3 SX 10 is shown in Figure 1. It is a rod-pumped well completed in the Upper and Lower Shannon formations at approximately 400 ft. The pump is set below the perforations. The casing is vented to atmosphere. The well produces to a local test manifold, where its production can be isolated from the other 20 or so wells that produce there, and sent to a test treater. Production from the test manifold goes to the tank battery where it is commingled with production from the rest of the field and separated to be sold to a pipeline. Historical test production rates for the well are shown in Figure 2.

Data Acquisition

The purpose of the test is to investigate the production increases that would be associated with providing nutrients to DNB populations during the H2S suppression treatments. A data collection program was designed to meet these objectives. It is based on the data collection program that worked well in the prior field testing program for the same technology.

In this previous test, the objective was to evaluate the levels of H2S suppression that were attainable in the field. The acquisition program in this test monitored the H2S concentration in the

casinghead gas stream, with occasional water samples being taken to monitor the dissolved H2S in the produced fluid. Bacterial cultures were also used to monitor populations of the major groups present.

In this test a similar data acquisition program was used with the addition of oil and water production data. Well tests were taken on the production rates two days per week at the test manifold. The H2S concentration in the casinghead gas is measured weekly at the wellhead with a Draeger tube. Water samples were taken twice per month in sterilized plastic bottles. These samples were refrigerated and shipped via overnight mail to GMT's laboratory in Oklahoma for analysis.

Treatment Schedule

The well was treated once per month with a nutrient solution. The solution was mixed using produced water 'in a chemical truck and gravity fed down the casing annulus. The well was shut in prior to the treatment. The initial treatment volume on October 1, 1997 was 120 bbls. It was mixed in two loads with a water truck. The well remained shut-in for a seven day period. The following treatments were 15 bbls each on or near the beginning of the month. These treatments were followed with an overnight shut-in. The final treatment occurred on March 2, 1998. The individual treatment dates and volumes are shown in **Table 1.**

Test Results

Production Rates

The well's test production rates are shown in Figure 2. Following the initial treatment on October 1, 1997, a slightly elevated oil production rate can be seen. Following the second treatment on November 6, very erratic production rates are noticed. This is thought to be due to the release of iron sulfide scale particles resulting from bacterial action. These solids caused sticking problems in the pump, requiring the pump to be dropped on November 12th, November 17th, November 18th, November 19th, and November 20th. After all these solids had cleared the pump, a six-week period of increased oil production can be seen. During this period, average production increased from three to five BOPD. After this period, production returned to near normal rates. Using the production data from May 1997 through September 1997 as a baseline, average oil production increased 7% over baseline and water production decreased 7% from baseline. Water oil ratio decreased 15% during the treatment period.

H2S Reduction

The concentration of hydrogen sulfide gas 'in the casing head gas was around 800 PPM prior to the treatments. Following the treatment, a significant depression in H2S concentration was noted, as can be seen in **Figure 1.** In a period of approximately two weeks, concentrations dropped to 100 PPM then started rising again, reaching 500 PPM prior to the next treatment on November 6. Following this treatment, concentrations of H2S again dropped to 125 PPM, only to begin rising again to 700 PPM prior to the next treatment. Following the third treatment, the reduction was only down to 500 PPM, rising again to 700 PPM before treatment #4. For the remainder of the test, H2S concentrations cycled between 400 PPM and 700 PPM. Overall, H2S concentration decreased 43% from the average concentration observed during the six months prior to the treatment period. It was hoped to achieve total H2S suppression during these tests, but the results seem to indicate that the treatment volumes should have been higher, and the frequency should have been higher to achieve better suppression.

Water Analyses The results of the produced water analyses are summarized in **Table 2.**

Volatile fatty acids were seen to generally increase throughout the test period. This indicates a lower level of bacterial activity, since both SRB's and DNB's require VFA's for metabolism. Since the levels of SRB's remained fairly flat throughout the test, and DNB levels grew significantly, there must have been a major suppression of SRB activity levels to account for an increase in VFA's. Except for the samples collected 'in January, the sulfate levels support these inferences. Sulfates were not present in the September samples prior to the treatment program. Sulfate levels jumped up quickly to 30 g/cc after the first treatment, and by the end of the program, had reached 40 g/cc. Clearly, the SRB's were no longer metabolizing the sulfates despite the fact that their population levels remained fairly steady.

The iron concentrations are inconclusive. They seemed to remain in a range from 25 to 40 g/cc from prior to the treatments through the treatment period. It was expected that a relatively large jump in iron would be seen as a result of the treatment, but that effect was not captured by the data acquisition program. In fact, when the greatest amount of solids were being produced through the pump in mid -November, the lowest iron concentration was measured (9 g/cc).

The changes in pH, TDS and nitrites are insignificant. Sulfide concentratrations were always found to be below measurement threshholds. There may have been a handling problem causing this.

Economics

Considering the cost of the larger treatments and the pumping equipment required to administer the treatments, the treatments used in this test were not as economic as the treatments used in the previous test, where one gallon of solution was dumped down the backside of the well once per week. Additionally, the H2S suppression was not as effective as in the smaller more frequent treatments. This treatment did, however, show a clear increase 'in oil production rates. The economics and effectiveness of treatments will vary from application to application, and no generalizations should be made on these results unless they can be confirmed with follow-on testing under different conditions.

Future Plans

The Bio-Competitive Exclusion process (BCX) has been demonstrated in multiple laboratory and field tests to greatly affect wellbore and reservoir ecology in a positive way. Sulfide reduction and prevention, and increased oil production are realistic benefits of consistent use of Max-Well 2000, the product formulae that initiate and perpetuate BCX.

Benefits are even further enhanced 'in waterfloods when Max-Well 2000 is introduced on the injection side, allowing the BCX process to occur throughout the swept portion of the reservoir.

Both BCX and the Max-Well formulae are patented, and are being marketed commercially by the LATA Group, Inc. Ochelata, Oklahoma.

Conclusions

1. Using the production data from May 1997 through September 1997 as a baseline, average oil production increased 7% over baseline and water production decreased 7% from baseline. Water oil ratio decreased 15% during the treatment period.

2. Overall, H2S concentration decreased 43% from the average concentration observed during the six months prior to the treatment period. It was hoped to achieve total H2S suppression during these tests, but the results seem to indicate that the treatment volumes should have been higher, and the frequency should have been higher to achieve better suppression.

3. Since the levels of SRB's remained fairly flat throughout the test, and DNB levels grew significantly, there must have been a major suppression of SRB activity levels to account for an increase in VFA's. Clearly, the SRB's were no longer metabolizing the sulfates despite the fact that their population levels remained fairly steady.

4. Considering the cost of the larger monthly treatments and the pumping equipment required to administer the treatments in this test, the treatments were not as economic as the treatments used in the previous test, where one gallon of solution was dumped down the backside of the well once per week.

5. The economics and effectiveness of treatments will vary from application to application, and no generalizations should be made on these results unless they can be confirmed with follow-on testing under different conditions.

Recommendations

1. Treatments should be fine tuned in the actual field situation in which they are to be applied prior to designing field-wide treatments. The data obtained at RMOTC shows how individual well conditions and field logistics can alter the economics of the treatments.

2. The treatment of more wells would lend additional statistical significance to the results. Although additional oil was obtained on this well, it must be repeated to prove the validity of the results.

3. Treat water injection wells and investigate the effectiveness of the BCX process on keeping waterfloods sweet.

Date	Cost	Description
12-Apr-92		Drill 12 1/4" hole to 138.62 KB. Ran 8 5/8" 24# K55 casing to 138.22'.
13-Apr-92		Finish running casing , cement w/ 100 sx class G.
24-Apr-92		MIRU, test BOP. Spud.
25-Apr-92		Drill 7 7/8" hole to 380'.
26-Apr-92		Drill to 482' TD. Ran electric logs. Ran 297.58' K55 15.5# 5 1/2" casing and 168.48' N80 20# 5 1/2" casing to 476.06' KB. Cemented w/ 120 sx class H.
27-Apr-92	$27,774	RDMO
20-May-92	$2,252	Dyna Jet ran Tempurature log to PBTD @ 426'. Ran GR/CBL/CCL/VDL from 426' to surface. (excellent cement bond)
4-Jun-92	$2,435	Dyna-Jet perf'd well from 334' to 364' (Lower Shannon) w/ 4 spf.
8-Jun-92	$4,245	RIH w/ tbg, pump, and rods.
15-Jul-92	$256	Pulled tbg, pump, and rods.
16-Jul-92	$12,860	Smith Energy frac'd well w/ 3000 gals 40# gel Borate pad, 1500 gals 40# gel 8 ppg 12/20 resin coated sand, flushed w/ 294 gals water. Ave treating pressure 380 psi, ave rate 20 bpm, ISIP 340 psi.
24-Jul-92	$916	Tagged sand @ 350' w/ sand pump. Cleaned out sand to TD. RIH w/ tbg, pump and rods. Hung well on.
14-Aug-92		FINAL REPORT: Stabilized production on 7-19-92 was 18.6 BOPD and 116.8 BWPD from the Lower Shannon.
13-Apr-94	$471	Pump 10 bbls 5% HCl solution down backside, let soak for 1 hr, return to production.
7-Jun-94	$314	Tag up on well, no fill. Change pump.
23-Sep-94	$243	Hole in 6th joint (junked 4 worn joints).
24-Sep-94	$1,251	Replaced 4 joints tbg and pump.
27-Oct-94	$284	Tag up at 420' (60' of fill). Found hole in 6th joint.
28-Oct-94	$707	Replaced 1 joint of tbg, RIH w/ tbg (SN at 385.45'). RIH w/ pump and rods, hung well on.
14-Dec-94	$122	TOH rods, pump.
15-Dec-94	$757	TOH tbg. TIH bit scraper to 204'. Stacked out. Perf US 278 - 298 4 SPF. SD darkness.
16-Dec-94	$11,824	Perf 258 - 298 4 SPF. Frac down 5 1/2" casing. Pumped 4000 gal pad, 600 gal 1 - 8 ppg, 1083 gals 8 ppg, 315 gal flush. 20 BPM, Avg P 700 psi, ISIP 52 psi. Total sand 11,364# 12/20 resin coated. Total fluid 143 Bbls.
21-Dec-94	$540	Tag sand 170. Clean out to 270.
22-Dec-94	$1,026	Bleed down. TIH and clean out 270-312.
23-Dec-94	$1,080	Bleed down. TIH and clean out 312-380.
27-Dec-94	$1,080	Bleed down. CO sand 380-410. Trouble getting good loads. Well flowing in cycles.
28-Dec-94	$1,374	Bleed down. CO sand 410 to 420. Land tbg 388' to SN. Swab. Well flows in cycles. Return 10 bbls 10% oil, no sign of sand. Flowed approx 60 bbls to pit while sand pumping. Run pump and rods. Acts like solids plugging valves.
29-Dec-94	$216	Well is pumping. Acts like solids are going through pump. Made 210 Bbls fluid overnight. RDMO.
3-Jan-95	$993	TOH pump. Botton ball cage had dropped off pump barrel. Tag @ 411. TIH new pump.
4-Jan-95	$81	RDMO
18-Jan-95	$672	Changed pump. Acted like plunger had lost traveling valve.
22-Mar-95	$405	Fill at 402'. Sand pump to 410. Could not make additional hole.
23-Mar-95	$647	RIH new pump, rods. Raised pump 19' for rathole.
26-Sep-95	$1,525	MIRU TOH with pump. top 7 rod boxes wer badly worn. Unlanded tubing and tagged at 410'. Found hole in 8th joint. Replaced a total of 4 joints. RDMO
1-Oct-97		Treated with 120 bbls nutrient solution, shut in for 7 days
6-Nov-97		Treated with 15 bbls nutrient solution, shut in overnight
5-Jan-98		Treated with 15 bbls nutrient solution, shut in overnight
5-Feb-98		Treated with 15 bbls nutrient solution, shut in overnight
2-Mar-98		Treated with 15 bbls nutrient solution, shut in overnight

Table 1. Well 653-3Sx10 History

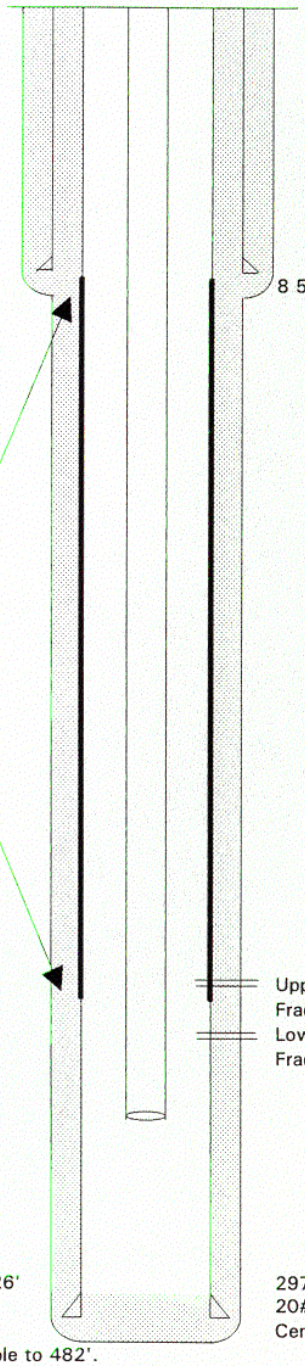
Sample Date	Volatile Fatty Acids	Sulfates	Sulfides	Iron	Sulfate Reducing Bacteria	Denitrifying Bacteria	General Aerobic Bacteria	pH	Total Dissolved Solids	Nitrites	Nitrates
	g/cc	g/cc	g/cc	g/cc	log of colonies/ml	log of colonies/ml	log of colonies/ml		parts per thousand	g/cc	g/cc
22-Sep-97	15	0	0	34	4	3	4	7.1	0.4		
23-Sep-97	6	0	0	38	4	3	4	7	0.4		
24-Sep-97	5	0	0	40	4	2	4	7.2	0.4		
9-Oct-97	2	30	0	14	4	5	5	6.8			
13-Oct-97	2	30	0	21	3	5	5	6.8			
20-Oct-97	8	12	0	23	3	6	7	7.1			
27-Oct-97	10	28	0	37	3	5	6	7.1			
6-Nov-97	16	20	0	40	5	6	6	6.7		0	0
13-Nov-97	7	37	0	9	3	6	7	6.8		20	100
2-Dec-97	26	34	0	29	4	6	5	6.9		0	0
9-Dec-97	21	37	0	22	3	7	7	6.9		10	50
5-Jan-98	11	0	0	33	4	4	5	6.9		0	0
13-Jan-98	5	0	0	34	3	7	7	6.9			
5-Feb-98	84	16	0	37	3	4	5	6.8		0	0
17-Feb-98	28	44	0	17	3	5	6	6.8		0	0

Table 2. Water Analyses Results

Date: 3/18/98

Well: 63-3 SX 10
Location: 1,960' FNL & 1,900' FEL
Section 10, T38N - R78W
Natrona Co., Wyoming

API 049-025-22529
Elevations: 5,189' GL
5,199' KB



12 1/4" hole to 138.62'.

8 5/8" 24# K55 casing set at 138.22', cemented to surface

20# N80 casing
138.13' to 306.61'.

2 7/8" tubing, SN at 372'.

Upper Shannon perfs 258 - 298 w/ 4 SPF
Frac'd w/ 11,364# 12/20 sand
Lower Shannon perfs 334' to 364' w/ 4 SPF
Frac'd w/ 13,300# 12/20 RCS

PBTD: 426'
Sand pumped to 410, 3/95

297.58' of 5 1/2" 15.5# K55 casing and 168.48' of 5 1/2" 20# N80 casing (138.13' to 306.61') set at 476.06'.
Cemented w/ 120 sx class H 40% silica flour

7 7/8" hole to 482'.

Figure 1. Well 63-3SX10 Mechanical Configuration

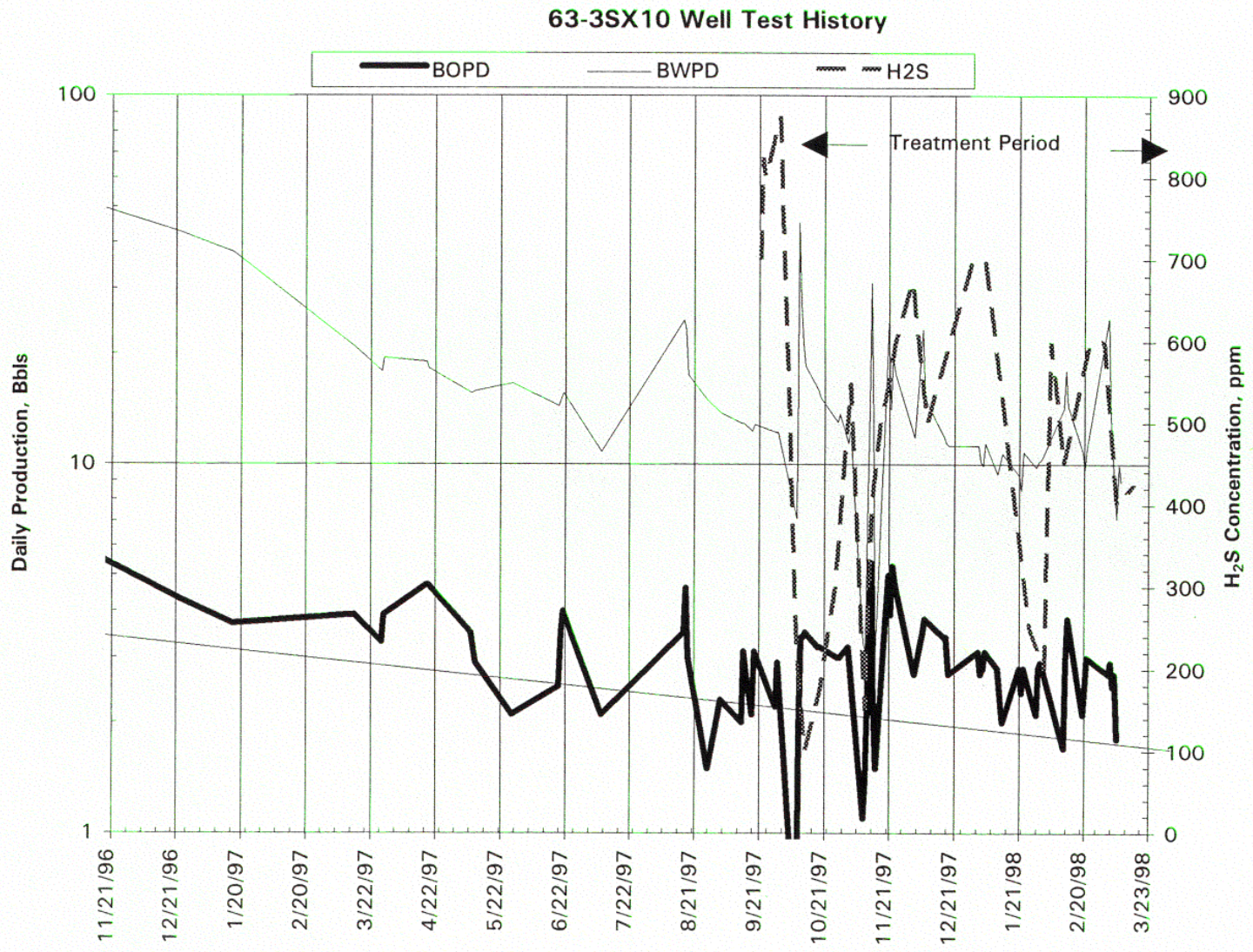


Figure 2. Well 63-3SX10 Test Production History