Coated Stages Improve ESP Runtime in the Howard-Glasscock Field of West Texas

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Abstract

Iron sulfide scale had caused a number of short runs in producing wells in this West Texas waterflood. A team of producing company engineers, operations personnel, chemical company technicians, and submersible pump company personnel was formed to identify the problem and research methods to correct the situation.

This paper presents a history of the field, problems encountered, characteristics such as loss of production that indicate downhole pump problems, and amp chart review. Chemical analysis of the produced water, along with scaling tendencies, were monitored. Metallurgical analysis of the pump parts exposed to the water, and detailed equipment teardown analysis helped identify the root cause problem. Once identified, steps were taken to reduce abrasive wear by coating pump stages to forestall the problem.

Introduction

The Howard Glasscock Field, discovered in 1927, is an onshore operation located in Howard County in the Texas Permian Basin as shown in Figure 1. There are 80 producing wells, twelve of which are submersible pump wells, in the Dora Roberts and West Howard Glasscock units. Figure 2 is a map of the field. Daily oil production averages 2500 barrels per day with producing wells making from 100 to 3000 barrels of fluid per day. The submersible pump wells make from 1000 to 3000 bfpd. The well depths are in the 2800 feet range, produce from the San Andres formation, and have shut in bottom hole pressures of 300 psi. Figure 3 is the stratigraphic column for the Howard Glasscock Field area.

Problem

In good operating conditions, it would be expected that submersible pumps would accumulate runtimes of several years. However, in the following conditions submersible pumps were experiencing 4 month average runtimes.

The Dora Roberts and West Howard Glasscock units produce an emulsified 29 degree API oil with water oil ratios of 10 to 100, and a gas liquid ratio of 100 scf/stkbbl. Hydrogen sulfide gas has a 200,000 ppm concentration and there is no carbon dioxide present. The bottom hole temperature is 95 degrees Fahrenheit and casing sizes permit the use of standard submersible pump equipment or non-slimline equipment. The casing sizes range from 5-1/2 inch, 11 and 14 pound per foot casing to 7 inch, 21 pound per foot casing. Tubing sizes used are 2-7/8 inch, 6.50 pound per foot, J55 and 3-1/2 inch, 9.30 pound per foot, J55. Submersible pumps operate in these downhole conditions with 20 to 50 psi pump intake pressures. Typical wellbore conditions are listed in Figure 4.

Case Studies

Two wells were used as case studies when submersible pump equipment was pulled after short runtime averages of 113 days run in Case 1 and 105 days run in Case 2. The equipment was pulled due to losses in pump efficiency which were indicated in amp chart readings and production data. Figures 5 and 6 show the production of the two case study wells with pump changeouts indicated. Production would decline from the designed volume while carrying a fluid level, indicating a loss in pump efficiency.

Teardowns and inspections of the submersible pump equipment were conducted after the premature failures. The teardown and inspection of the equipment in Case 1 and Case 2 indicated that both subject equipment had failed due to abrasive wear in the pumps. Grooves and holes were worn into the wall of the diffusers just above the O-ring groove that continued through the housing of the pumps. This wear can be seen in Figures 7-11.

A sample of the produced fluid and solids were taken from the pumps to identify the elements of the solids. The analysis identified heavy amounts of iron sulfide, light amounts of calcium carbide, and trace amounts of sand. It was determined that abrasive erosion was occurring due to the heavy amounts of iron sulfide scale.

The submersible pump equipment experiencing the abbreviated runlives were standard floater stage designs. To handle the abrasive wear problems being experienced by the submersible pump equipment in the two case wells, an abrasion resistant pump design was needed. Typical abrasion resistant pump designs use special bearings to radial stabilize pump shafts and use compression staging of pump impellers to protect against downthrust wear. However, with severe wear occurring along the wall of the diffuser, a means to increase the wear resistance in the bowl area of the diffuser was needed. The method selected for adding abrasion wear resistance to the diffuser wall was through a coating. Abrasion resistant coatings that do not adversely effect pump performance, are not of a cost prohibitive material or application, and could be applied to a standard diffuser offered a quick and inexpensive possible solution. The applied coating can be seen in Figures 12-14.

Coated submersible pumps were installed in the two case wells. The runtimes of the standard design pumps and the coated pumps can be seen in Figure 15. In Case 1 three standard pumps were run with an average runtime of 113 days. Inspection of the three standard submersible pumps showed abrasive wear cutting grooves into the diffuser walls. A coated pump was then installed. After 102 days the coated pump was pulled and torndown. Inspection of the coated pumps indicated little or no erosion of the coated diffuser walls. In Case 2, a standard submersible pump was pulled after 105 days run due to low production. Inspection of the standard design pump showed the same abrasive wear cutting grooves into the diffuser walls as was seen in Case 1. A coated submersible pump was installed. It has run for 245 days and is accumulating additional runtime. This is an increase in runtime of 4.5 months or 233%.

Conclusion

The good condition of the diffuser walls and coating seen during the inspection of the coated pumps from Case 1 was a sign that the coating design was providing the wear resistance needed. The additional runtime being gained in Case 2 is providing more evidence that the coated submersible pump is an effective design for handling abrasive wear of diffuser walls due to high volume, high velocity fluid flow containing iron sulfide scale. The additional runtime seen in Case 2 has provided costs savings in equipment and rig time. The cost savings have provided the necessary results to try more of the coated submersible pump designs.

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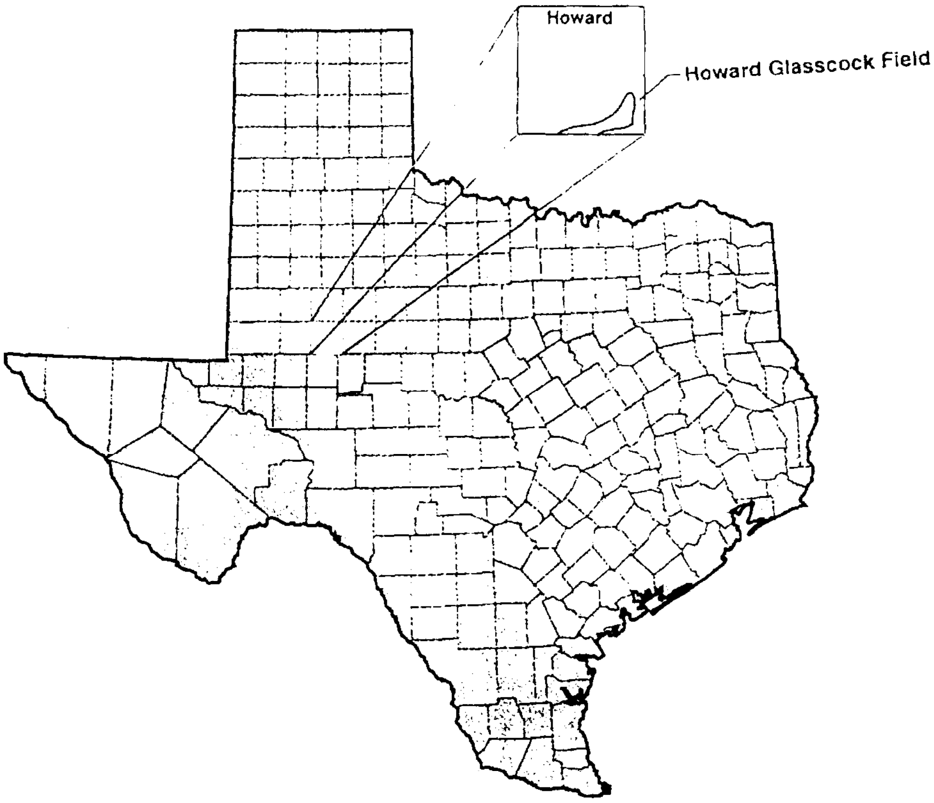

Figure 1 - Howard Glasscock Field Location

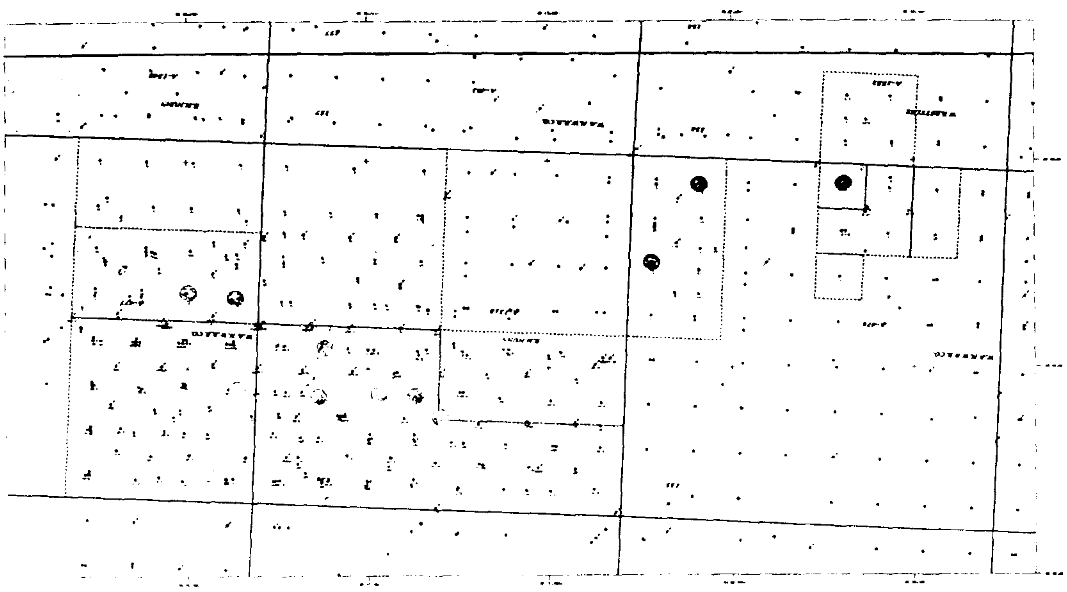

Figure 2 - Howard Glasscock Field Map

Stratigraphic Section

General Eastern Shelf
Howard & Glasscock Co.,'s Texas

System	Formation	
Permian	Dewey Lake Rustler Salado	
	Tansill Yates Seven Rivers Queen Grayburg San Andres San Angelo	
	Sprayberry	Leonard
	Dean	Wolfcamp
Pennsylvanian	Absent or Thin	Cisco
		Canyon
	Strawn	
	Atoka	Bend
	(Absent)	
Mississippian	Chester Meremec- Osage	"Barnett"
	Kinderhook Woodford	
Devonian	Devonian	
Silurian	Silurian SH. Fusselman	
Ordovician	Sylvan Montoya	
	Simpson	
	Ellenburger	
Cambrian	Cambrian	
Pre-Cambian		

Figure 3 - Howard Glasscock Stratigraphic Section

QUANTITY	FROM	TO
NO. OF WELLS	80 PRODUCING	
AVG. BFPD	100	3000
SIBHP, PSI	300	
PUMP INTAKE PSI	20	50
GLR, SCF/STKBBL	100	
API, SPECIFIC GRAVITY	29	
WOR	10	100
BHT, F	95	
TBG, O.D. (IN) & WT.	2-7/8" (J55, 6.50)	3-1/2" (J55, 9.30)
CSG, O.D. (IN) & WT.	5-1/2" (11 & 14)	7" (21)
TVD, FEET	2800'	
MD, FEET	2800'	
SCALE	CALCIUM CARBONATE (LIGHT)	IRON SULFIDE (HEAVY)
SAND	SAND (TRACE)	
H2S	200,000 PPM	
CO2	0	
EMULSION	YES	
ON/OFFSHORE	ONSHORE	

Figure 4 - Wellbore Conditions

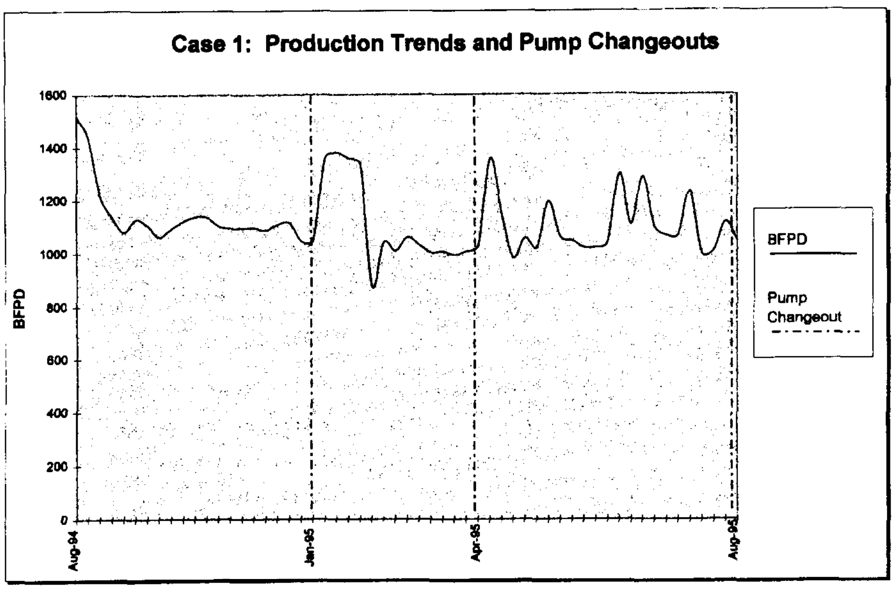

Figure 5

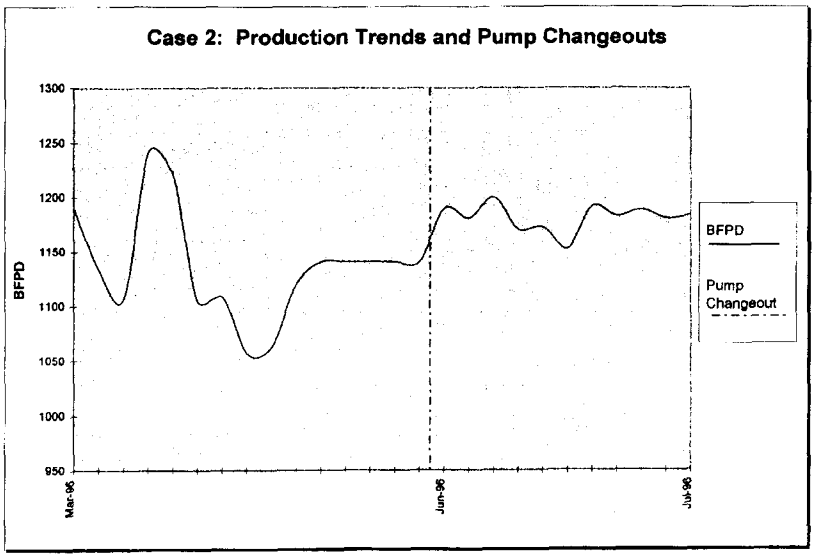

Figure 6

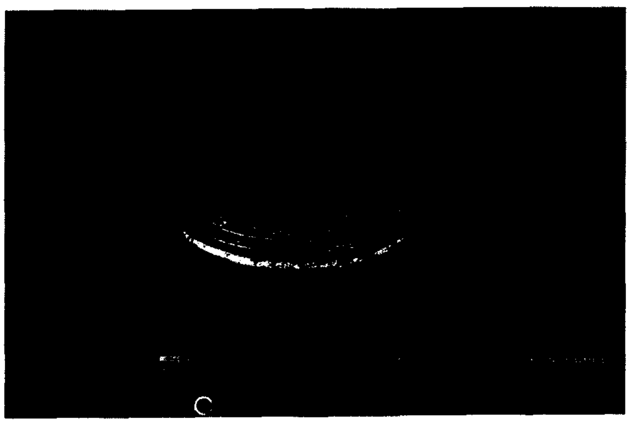

Figure 7 - Submersible pump diffuser with hole shown

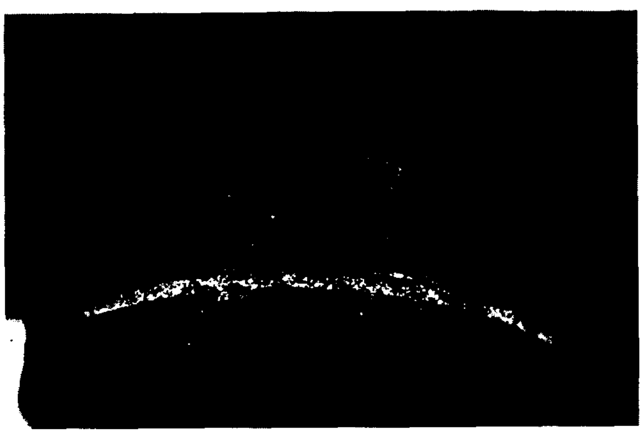

Figure 8 - Close-up of a submersible pump diffuser with hole shown

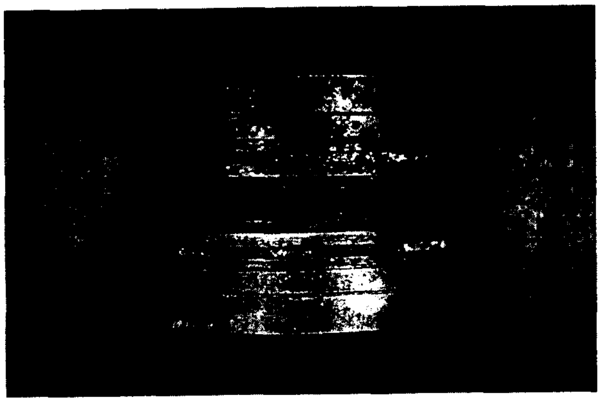

Figure 9 - Submersible pump diffuser with hole shown.

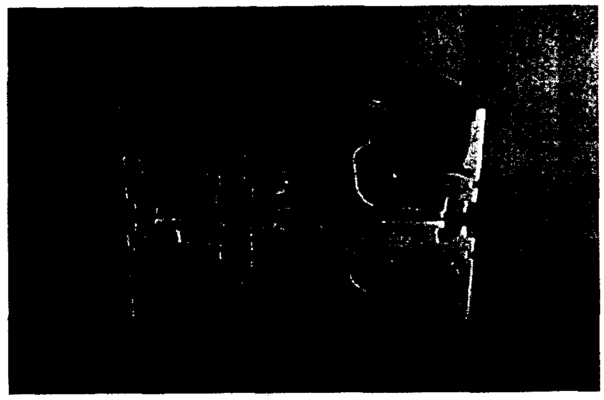

Figure 10 - Submersible pump diffuser with grooves shown.

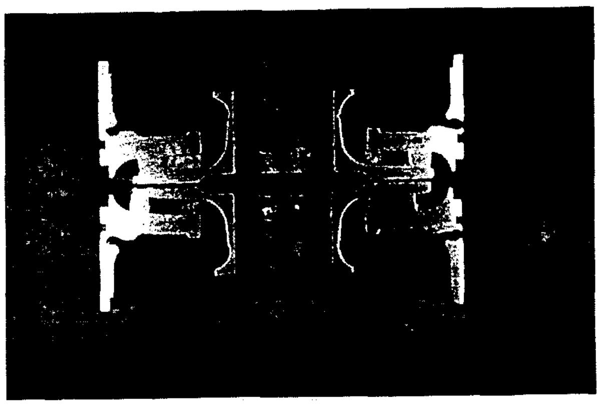

Figure 11 - Submersible pump diffuser with grooves shown.

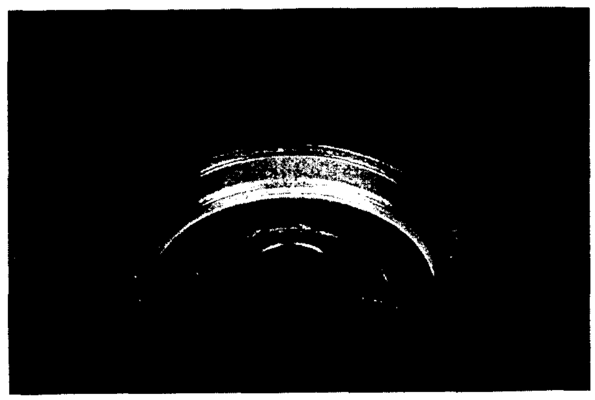

Figure 12 - Oblique view of a coated submersible pump diffuser.

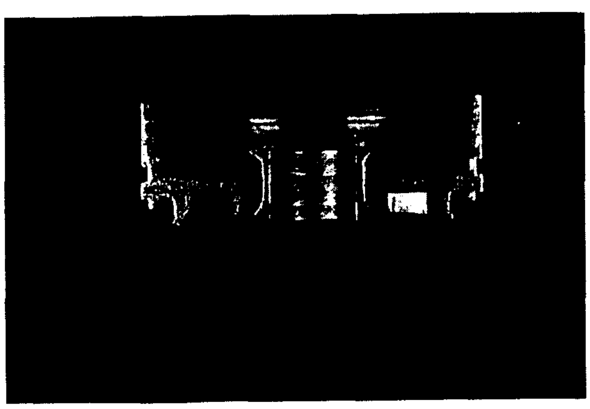

Figure 13 - Cross-sectional view of a coated submersible pump diffuser.

Figure 14 - Top view of a coated submersible pump diffuser.

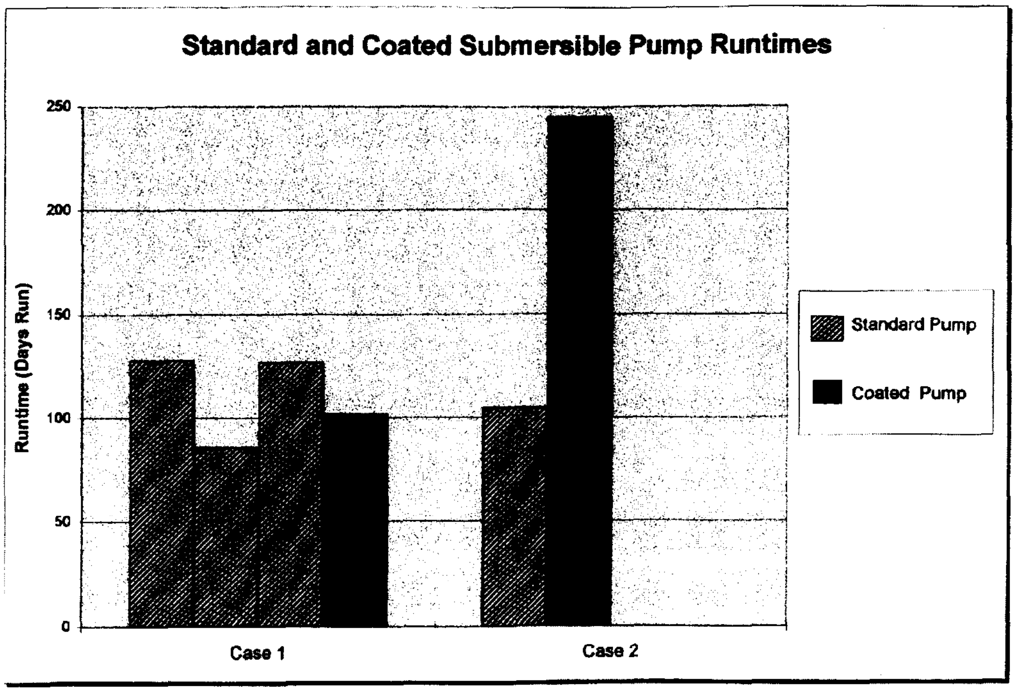
Standard and Coated Submersible Pump Runtimes
Runtime (Days Run)
250
200
150
100
50
0
Case 1
Case 2
Standard Pump
Coated Pump

Figure 15