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Application of ESP Oil Water Separation System in the Swan Hills Unit One Field-A Case Study

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Abstract

As water production in mature oilfields continues to increase, we as an industry are continually challenged with how to handle the ever-increasing volumes of produced water. A unique technology in the form of downhole oil/water separation may be a solution.

This paper is a description of the application of the Downhole Oil/Water Separation technology in the Swan Hills area of Alberta, Canada. The well is located in the Swan Hills Unit No. 1 field, operated by Anderson Exploration. Well 08-17-67-10 was chosen to try the downhole oil/water separation technology.

The processes of selecting the candidate well and installing the Downhole Oil/Water Separation System are discussed. Also included are the production results before and after installation of the system and the system operation performance.

Installation of this system increased oil production from well 08-17-67-10 from 176 to 264 BOPD. Surface water production from this well was reduced from 3650 to 189 BWPD which will allow for a shut-in well to be restored to production for an additional production gain of 80 BOPD. These two factors resulted in a four month payback of investment.

Introduction

Associated water production increases the cost of producing oil and limits the amount of drawdown that can be achieved on certain wells because of surface water handling constraints. The Downhole Oil/Water Separation technology provides a solution to this problem in certain applications.

Anderson Exploration became intrigued with the technology and decided to test it at Swan Hills (See Field Conditions of Swan Hills in Figure 1.). Anderson decided to test at Swan Hills for the following reasons:

- To determine if Downhole Separation was a viable technology which could help alleviate the water handling constraints at Swan Hills
- To determine if Downhole Separation was a viable technology for other oilfields
- The water system at Swan Hills was operating at its upper limits. If a conventional ESP had been run on Swan Hills 8-17-67-10 to produce 220 BOPD, 3100 BPD of surface water production would be required. The surface water handling facilities could not accommodate this volume without a shut-in of production from another well.

Candidate Selection and Evaluation

The following criteria were developed to assist in the screening of potential candidates.

- 7” casing was desired to maximize producing rate and allow for better clearance than 5-1/2” casing (The overall length and cost of a 5-1/2” system was also a deciding factor)
- Only wells with a water-cut of greater than 94% would be considered
- Avoidance of wells with a history of asphaltine and scale problems
- Avoidance of wells with high GOR’s

Throughout the screening and selection process, a team consisting of a production engineer, a reservoir engineer, and a geologist worked closely to ensure the best candidates were selected. Ten candidates were initially selected. This list was reduced to five candidates. All five wells which survived the initial screen were considered good candidates.

It was important to ensure that “solid” candidates were in the queue, because once the initial workover process was started, should problems arise, such as no isolation between the proposed injection and production zones, or insufficient inflow of the production zone once an injection zone was established, without investing a great deal of money, we could move to the next well and utilize much of the same equipment.

CFER (Centre for Engineering Research) assisted Anderson in the screening process by working through a candidate ranking list. CFER also advised as to the relative merits of each candidate in the selection process. They also acted as means of double checking our processes to ensure no "surprises" would occur. Of the five candidates, the well 08-17-67-10 seemed to be among the best choices. CFER and the vendor both reviewed the well data after the first workover. Both companies reviewed the final equipment sizing and have been an asset in this project.

A thorough review of the candidate was carried out to confirm the selection. The geologic characteristics of the well and its offsets was considered using 3-D geologic models. The offset production and injection history was also considered. It was concluded that injection into the B2A carbonate zone of 8-17-67-10 would not negatively impact the recovery of its offset producers.

The available logs were reviewed on the subject well. The CBL and Neutron-Density logs suggested that injection into the B2A zone would be isolated from the upper productive zones.

Finally, production and economic forecasting were performed on the application. Production was predicted to increase from 157 (production of the upper zones after the workover to convert the B2A zone to injection) to 220 BOPD. Payback was anticipated to occur in 3.2 months.

Equipment Selection and Description

Figure 2 illustrates the completion design and equipment selected for the well (Note that this is actually the currently installed equipment, which is slightly modified from the initial string.). A 540 series single pump, *Push Through* design was selected using an injection pump which was designed to process 2200 BPD of fluid. The single pump design was selected because of the high injection pressure required to inject the fluid into the formation (4200 PSI) and the mechanically simpler design. It is noteworthy that this was the first complete 540 series Downhole Oil/Water Separation unit to be run in a well.

Compression pumps were run to expand the pumping range of operation. A downhole monitoring package was also run to measure injection and producing pressures and flow into the injection zone. The system was coupled to a variable speed drive in order to maximize operational flexibility.

Completion Procedure and Start-up

Prior to the workover to convert this well to Downhole Oil/Water Separation, 08-17-67-10 produced 176 BOPD and 3685 BWPD.

A workover to convert the lower portion of the producing zone to injection was initiated on March 23, 1996. The lower portion of the perforations was isolated using a permanent packer. (A permanent packer with seal bore extension was selected in order to prevent compressive forces on the Downhole Separation System.) Isolation was confirmed using pressure testing.

The injection zone was acidized with 1000 gals. of 15% HCL. A seven step injectivity test was run to establish the injectivity index of the B2A zone.

After a plug was set in the packer, the upper perforations were swabbed to establish inflow rate and sizing for a test ESP.

The test ESP was run in the well on April 3. This test was terminated after two months. The production rate of the upper zone using the test pump was 138 BOPD and 1428 BWPD.

The Downhole Separation System was installed July 17. The well was circulated to remove oil from the casing annulus prior to installation of the unit. The system was designed to process 2200 barrels total fluid downhole.

Discussion of Results

Operation

The Downhole Separation System performed well from installation on July 17, 1996 until a downhole short occurred on December 25. Subsequent inspection of the motor revealed that the failure was cause by excessive rotor growth. This failure was not caused by the Downhole Separation System.

The decision was made to replace the three 3/8" fluid bypass tubes with two 5/8" tubes in an attempt to increase the flow capacity of the transfer tubes and increase production by 65 BOPD. This was the first time that the 5/8" tubes had been run into a well. The unit failed to lift fluid to surface after 36 hours of operation. Upon pulling, a hole in one of the transfer tubes was observed. It was apparent that the tubes were damaged by bands sliding and being wedged into the transfer tubes. Tolerances in this well were just too tight for the increased tube diameter. Design changes have been implemented which will minimize the risk of this damage without compromising flow capacity.

A final problem occurred. Upon reinstallation of the unit, the shaft in the injection pump twisted off. Subsequent dismantle revealed excessive upthrust on the stages of the injection pump. It is believed that this may have been due to improper shimming of the compression ring pump, however, design changes have been instituted which will decrease the chances of this reoccurring.

The unit is currently running smoothly. Production has been slow to return since the last installation, however it is increasing.

Production and Economics

As observed in Figure 2, production on 8-17-67-10 increased by 82 BOPD because of additional drawdown. Approximately 3450 BWPD additional water handling capacity is now available because of the reduction in surface water production from 8-17-67-10. This capacity will be used to restore 80 BOPD from another well to production.

The original AFE was overspent by $100,000.00. Despite this overexpenditure, based on the above production increase, the workover to install the Downhole Oil/Water Separation System resulted in a 4.3 month payout on the original investment.

The unplanned expenditures which occurred in January and February have extended the payback on the system, however, indications are that production from the well is increasing, and should return to December levels.

Conclusions

The process described above resulted in the selection and successful conversion of Swan Hills 8-17-67-10 to Downhole Oil/Water Separation.

Based on an additional 82 BOPD from this well because of additional drawdown, and on a reactivated 80 BOPD from another well because of the 3450 BPD water reduction from 8-17-67-10, the initial investment paid out in 4.3 months.

In spite of the referenced technical glitches, which have extended payout somewhat, the dramatic results from the workover illustrate the promise of Downhole Oil/Water separation.

Acknowledgments

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Swan Hills Field Conditions

QUANTITY:	FROM:	TO:
Number of Wells	136	
Average BFPD	400	4800
SIBHP (PSI)	2400	3800
Pump Intake (PSI)	400	2300
GLR, SCF/STB	20	300
API (S.G.)	40	
WOR	3	60
BHT (F)	200	240
Tubing OD (IN)	2.38	2.875
Casing OD (IN)	4.5	7
TVD (FT)	8200	8800
MD (FT)	8200	9000
Scale	Light	Moderate
Sand	None	None
H_2S (%)	0	.02
CO_2 (%)	0	2
Emulsion	No	
On/Offshore	Onshore	

Table 1

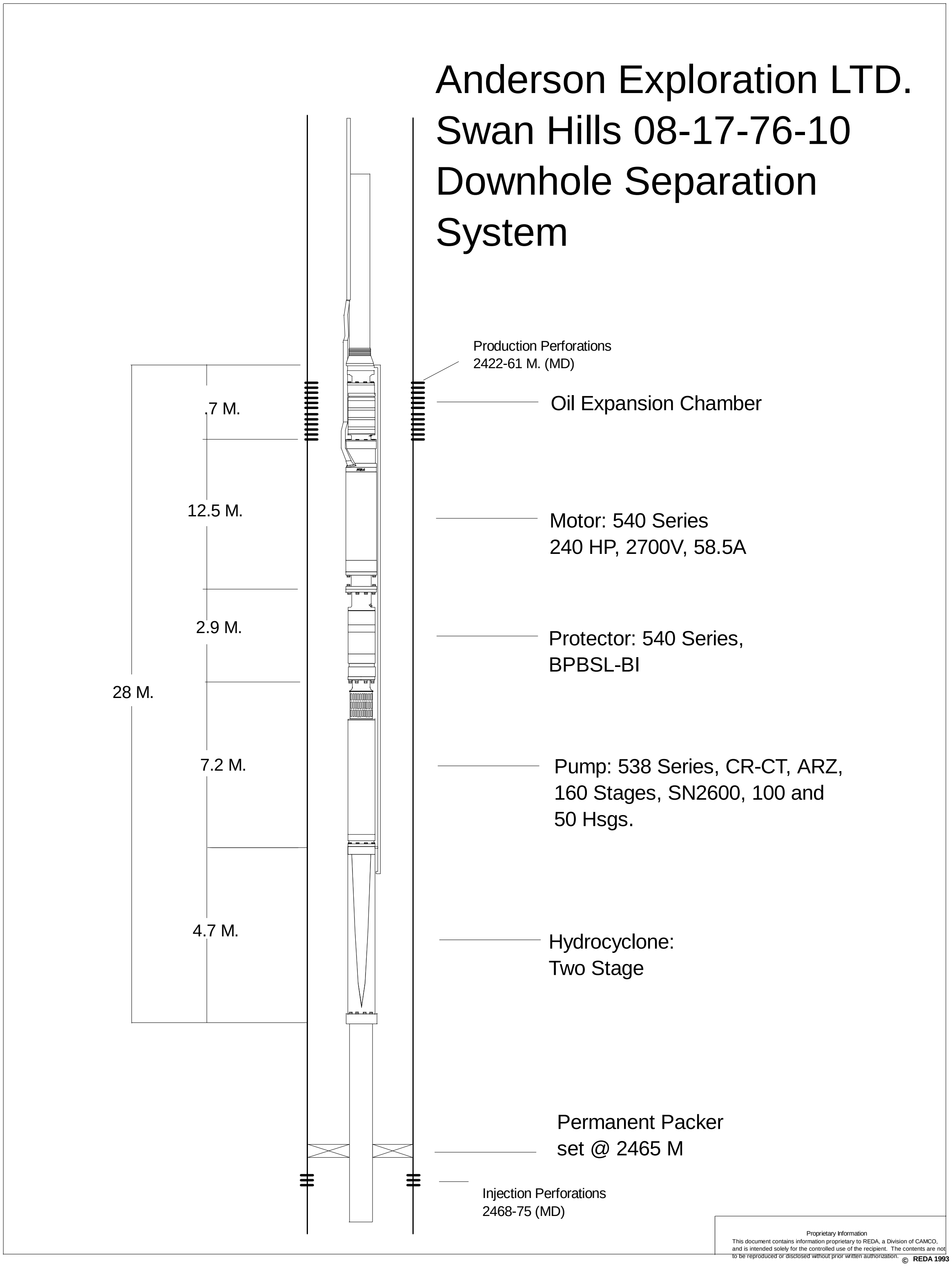
Anderson Exploration LTD.
Swan Hills 08-17-76-10
Downhole Separation
System
Production Perforations
2422-61 M. (MD)
Oil Expansion Chamber
Motor: 540 Series
240 HP, 2700V, 58.5A
Protector: 540 Series,
BPBSL-BI
Pump: 538 Series, CR-CT, ARZ,
160 Stages, SN2600, 100 and
50 Hsgs.
Hydrocyclone:
Two Stage
Permanent Packer
set @ 2465 M
Injection Perforations
2468-75 (MD)
.7 M.
12.5 M.
2.9 M.
28 M.
7.2 M.
4.7 M.
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Figure 1

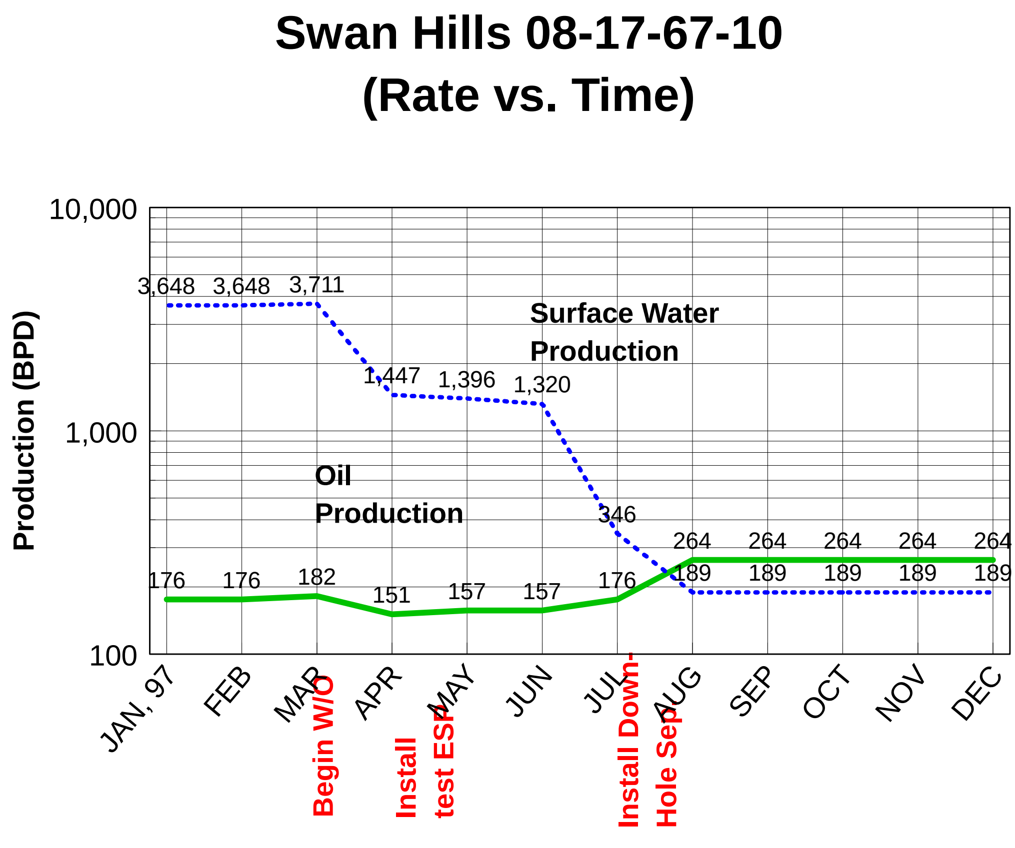
Swan Hills 08-17-67-10
(Rate vs. Time)
10,000
1,000
100
Production (BPD)
3,648
3,648
3,711
1,447
1,396
1,320
346
Surface Water
Production
Oil
Production
264
264
264
264
264
189
189
189
189
189
176
176
182
151
157
157
176
JAN, 97
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Begin W/O
Install
test ESP
Install Down-
Hole Sep

Figure 2