ORGANIC OIL RECOVERY

Scott Field North Sea Pilot

July 2020

BACKGROUND

- Operator – CNOOC Petroleum Europe Limited
- Asset – Scott Platform
- Location – UKCS
- Trap Type – Structural
- Pay Zone – Scott & Piper Formation
- Formation Age – Upper Jurassic
- Depth to Crest – 10,400ft
- Permeability – 0.1 to 6,500mD
- BHT – 96°C (205°F)

The Scott Field, located in the UK Central North Sea, is in a mature stage of development. The oil field is developed in the highly-productive Upper Jurassic Humber Group sandstones of Oxfordian to Kimmeridgian age. The field was discovered in 1983, sanctioned in 1990, and produced first oil in 1993.

Scott is located about 187 kilometres northeast of Aberdeen in 142 metres of water. The Scott Field reservoir exhibits elements of both stratigraphical and structural trapping. The field structure, effectively a large southward tilted fault block, is compartmentalised into a series of four main pressure isolated fault blocks by mid to late Jurassic faulting. Current modelling is aimed at targeting bypassed oil to increase ultimate recovery.

CNOOC Petroleum Europe Limited, a wholly-owned subsidiary of CNOOC Limited, is the operating partner of Scott (41.89%), with Dana Petroleum E&P Limited (20.64%), Edison E&P UK Ltd. (10.47%), NEO Energy Production UK Limited (5.16%) and MOL Operations UK Limited (21.84%).

>1,000% +	>25,000	4%	< 1 week
ROI*	barrel incremental	drop in water cut	payback

* Incremental revenue over pilot cost

CUSTOMER CHALLENGE

Identify an alternative, cost-effective EOR technology to increase oil production and recoverable reserves

Implement EOR technology with zero CAPEX outlay

Implement EOR technology with a minimal offshore footprint

PILOT INJECTION PROCEDURE

- 2,400 barrels of injection quality seawater and nutrient mix (>99% water, <1% nutrient) injected at 4 barrels/min directly at the wellhead
- Over-displacement of approxmately 400 barrels of injection quality seawater at 4 barrels/min
- Shut in Well for 7 days (Incubation period)
- Second over-displacement of approxmately 1000 barrels of injection quality seawater at 4 barrels/min to push newly formed near well-bore ecology further into reservoir
- Shut in Well for a further incubation period of 3 days
- Return to Production

OOR APPROACH

The application of the OOR Process® generally consists of the following steps:

Initial field screening

Well sampling and laboratory analysis

Pilot injection application

The application of the OOR pilot process for the Scott field consisted of the following steps:

Step 1 – Field Screening of Reservoir Characteristics and Well Specific Data - Completed

Step 2 – Target Well Sampling & Laboratory Analysis - Completed

Step 3 – Single Well Pilot Test (In-Situ Microbial Response Analysis - ISMRA®) - Completed July 2020

The In-Situ Microbial Response Analysis (ISMRA®) or Pilot Test is designed specifically to replicate the laboratory results in the reservoir. Produced water samples were taken pre OOR nutrient injection and just after Well flow back. A significant production response is often observed; however, the most important aspect to this step is the microbial response observed in the laboratory from samples taken upon return to production.

Step 4 – Targeted Water Flood Implementation

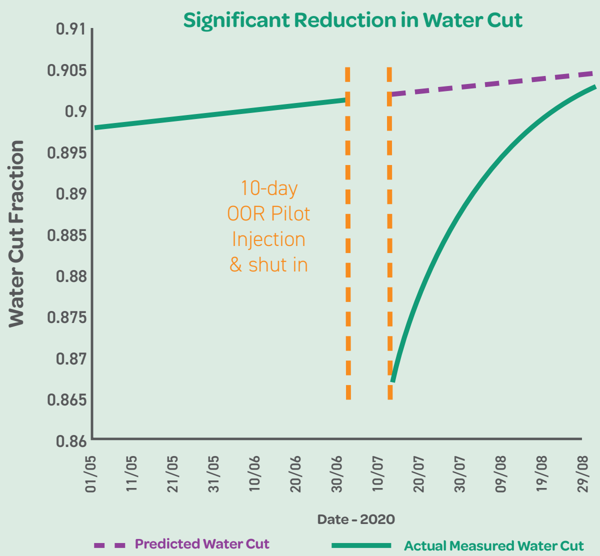
Progression to step 4 – Targeted water flood implementation – will be confirmed once the microbiology and the production impact has been assessed

Step 5 – Full Field Implementation

RESULTS/INCREMENTAL OIL PRODUCTION

OBSERVATIONS

- Significant Incremental Oil gain
- Lowest water cut since May 2016
- No change to oil quality
- No change to separation efficacy (same oil-in-water content)
- Observed reduction in H_2S in oil and gas phase



WHAT OUR CUSTOMERS SAY

"Promising results from an elegant EOR technology that can be implemented without a large offshore footprint"

– Andy Bostock, CNOOC International

"For us, it was a basic pumping operation. Very similar to a scale squeeze, although smaller volumes and therefore slightly more straightforward."

– Nigel Wallace, Altus Intervention

ORGANIC
OIL RECOVERY

Petrogas Rima South Oman Pilot

February 2021

Fig 1 – Well Site Operation

BACKGROUND

- **Operator –** Petrogas Rima
- **Field –** Jalmud (Rima Small Fields)
- **Location –** South Oman Onshore
- **Trap Type –** Haima Pods/Turtle-back
- **Formation Age –** Permian (Gharif, part of the Haushi Group)
- **Depth –** 2,750 to 3,500ft
- **Permeability –** 200 to 700mD
- **BHT –** 60°C (140°F)
- **Well –** JM-08

Jalmoud "JM" Field is a sub-field located within Rima Satellite Small Field. The first production from the field was in November 1986 from JM-02. The main producing reservoirs in the field are Gharif and Al Khalata.

Anticline traps are turtle-back structures or called Haima Pods (four way dip closure mainly) that are sealed by Khuff shale and the intraformational shale within Gharif sand packages. The Gharif Formation can be divided into three units; the Lower, Middle and Upper Gharif. The depositional environment comprises proximal channels and sheet floods in the Upper and Middle Gharif (1/2), estuarine/tidal in Middle Gharif (3) and fluvial & wave dominated deltas in the Lower Gharif.

The field production mechanism is driven by using initial pressure along with the artificial lifting techniques and secondly by utilising the Waterflooding mechanism in Middle-Gharif 1 and Middle-Gharif 2.

To date 32 wells have been drilled in the Jalmud Field, 24 vertical wells and 8 wells drilled as deviated (S-shape). Currently 25 wells are active (2 as water injectors, 1 is considered as water source well, 22 wells are Oil Producers with total net production of approximately 250m^3/day (1,570bbl/day).

Fig 2 – Regional Map

CUSTOMER CHALLENGE

Identify an alternative, cost-effective EOR technology to increase oil production and recoverable reserves

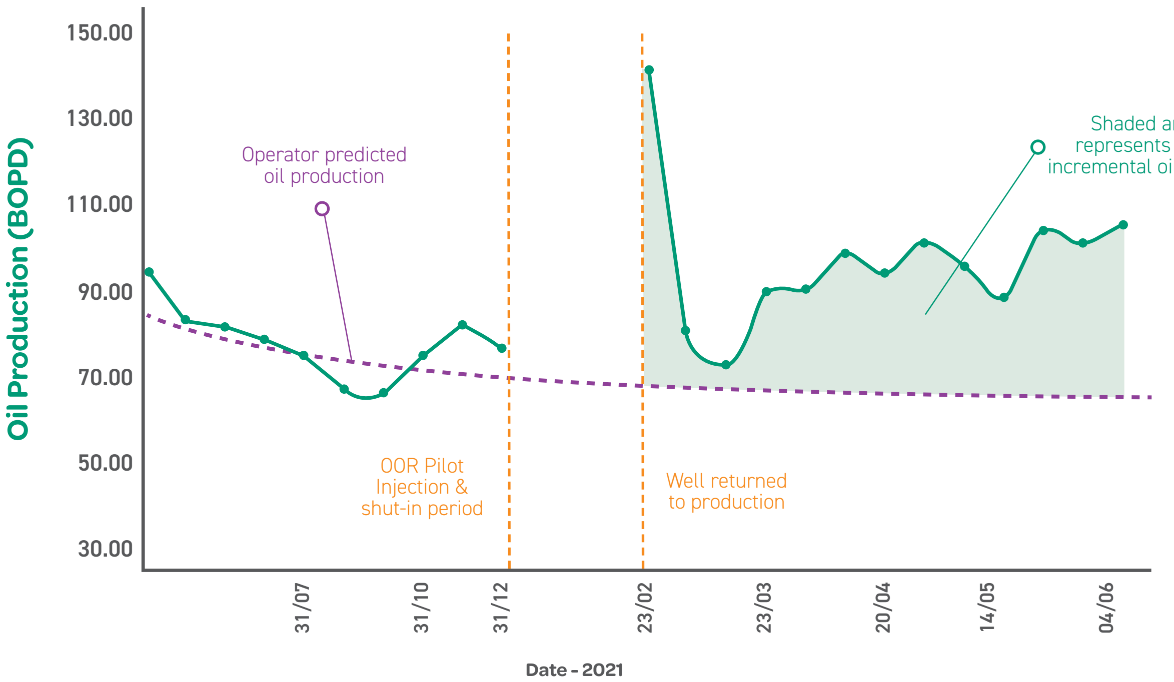
Implement EOR technology with zero CAPEX outlay

Implement EOR technology with minimal logistical and operational considerations

PILOT INJECTION PROCEDURE

- 410 barrels of injection quality produced water and nutrient mix (>99% water, <1% nutrient) injected at 2 barrels/min directly at the wellhead
- Over-displacement of approximately 390 barrels of injection quality produced water at 2 barrels/min
- Well shut-in for 7 days (incubation period)
- Second over-displacement of approximately 260 barrels of injection quality produced water at 2 barrels/min to push newly formed near well-bore ecology further into reservoir
- Well shut-in for a further incubation period of 3 days
- Return to production

RESULTS/INCREMENTAL OIL PRODUCTION



WHAT OUR CUSTOMERS HAD TO SAY

"Cost effective technology which is easily deployed with no hoist entry or workover required, as Petrogas Rima, we have shared in OOR's excitement about the trial in Jalmud Field which is the first of its kind in Oman. The post treatment production and lab results in the oil producers have shown an excellent response, and targeted microbial activation and growth which gives us the confidence to move to next step of treating water injectors. We are keen to move ahead at the soonest."

– Nabil Al Harthy, Petrogas Rima

ORGANIC OIL RECOVERY

MEMBER OF MOL GROUP

MOL HUNGARY PILOT SUCCESS

May 2022

BACKGROUND

- **Operator –** MOL Hungary
- **Field –** Algyő
- **Location –** Onshore Hungary
- **Trap Type –** Structural Four-Way Dip-closure Trap
- **Formation Age –** Miocene to Pliocene (Pannonian s.l.)
- **Depth –** 6,400ft
- **Permeability –** 200 to 700mD
- **BHT –** 98°C (208°F)
- **Well –** A-290

Algyő field is Hungary's largest oil and gas accumulation located SE of the country close to the Serbian border. The field was discovered in 1965 and is a multi-reservoir field with three main reservoirs including Algyő-2 with the OOR pilot well A-290.

Algyő-2 reservoir is a structural four-way dip-closure type of trap. The formation environment is delta interdistributary bay-fill and delta front and delta slope. The facies are distributary channels, mouth bar complex and delta front bars. The reservoir rocks are dominantly sandstone and aleurolite. The driving mechanisms are gas cap and natural water inflow. In the past the reservoir was exploited by 146 oil and gas wells although the current number of active producer wells are considerably less. Most of the wells produce with gas lift with water cut averaging higher than 95%. From 1969 till the end of the nineties water injection was applied to enhance the production and the recovery. Other small scale EOR technologies were also applied on a small area of the reservoir. The current recovery factor of the reservoir is around 47%.

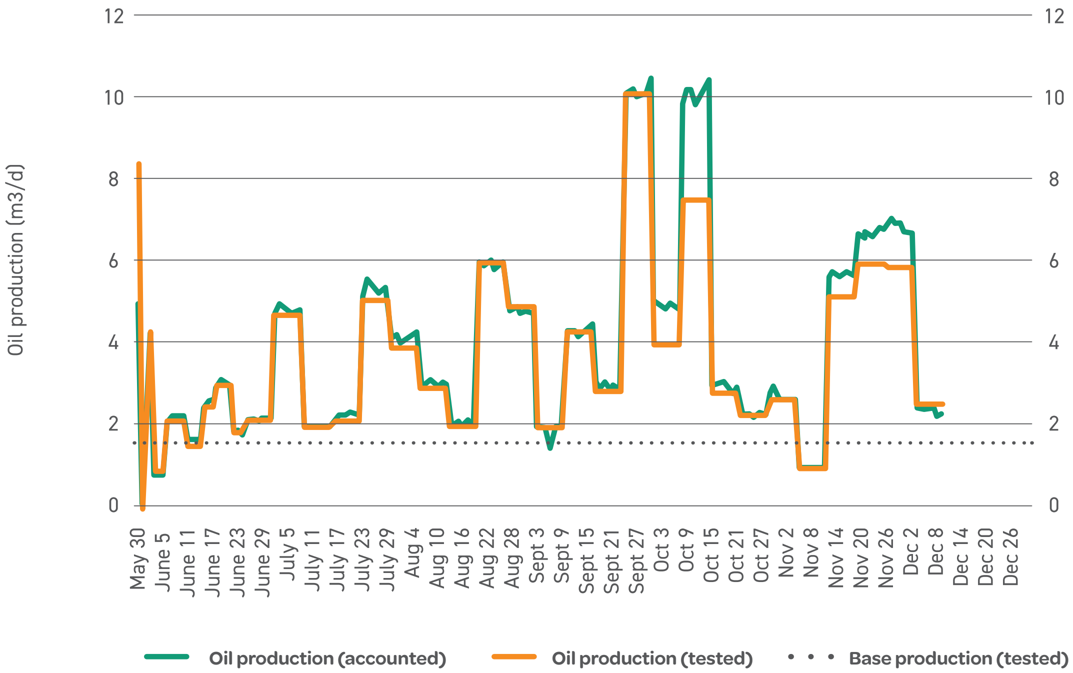
>700% +
ROI*

>2,600
barrel incremental

< 3 week
payback

* Incremental revenue over pilot cost

A- 290 OIL PRODUCTION AFTER REOPENING



WHAT OUR CUSTOMERS HAD TO SAY

> Using Hunting's guidelines, the preparation for the implementation is simple and easy. No need for expensive preparatory works and CAPEX. Implementation of the technology on the field (well treatment) is also simple, it needs only a mixing technology and a pumping unit. The pilot (ISMRA) on our Algyő well A-290 can be considered successful. The water analysis in the OOR lab showed good microbial response after the treatment with multiple growth of the original microbe count. The growth of microbes resulted in a decrease in water cut which increased net oil production.

– János Szelényi, MOL Plc.

ORGANIC
OIL RECOVERY

Bahrain Rubble Pilot

August 2020

BACKGROUND

- **Operator –** Tatweer Petroleum
- **Reservoir –** Rubble
- **Location –** Bahrain Field Onshore
- **Formation Age –** Late Cretaceous
- **Rock Type –** Carbonate (Limestone)
- **Depth –** 2,750 to 3,500 ft
- **Permeability –** 3.5 mD
- **Oil Gravity –** 18 °API
- **BHT –** 48°C (120°F)
- **Well –** A

In the Mishrif formation (locally know as Rubble) underlying the Aruma, the oil properties vary laterally across the structure. It is estimated that only 10% of Original Oil in Place (OOIP) to be light oil (20 to 30 API) mainly concentrated in the east and northeast flank of the reservoir, whereas the remaining 90% is classified as heavy oil (below 18 API). The gravity significantly decreases heading south until it reaches 12 API with viscosities reaching 400 cP. The current average reservoir pressure is estimated around 300 psia (initially 600 – 700 psia) and temperature is ~120° F. The initial solution GOR is 28 scf/bbl and bubble point pressure is 316 psia. Water salinity is around 80,000 to 100,000 ppm NaCl.

In Bahrain the late Cretaceous Mishrif formation is known as the (Rubble) limestone. Its name reflects its abuse by extensive erosion, karsting, faulting and fracturing. Two dominant fault sets exist, both associated with Late Cretaceous regional compressional events. NNE-SSW relaying faults dominant the axis of the anticline, whereas later NW-SE trending strike-slip wrench faults cut across the field, but most prominent on the structural flanks. Both fault sets extend below the Rubble, passing through the underlying LS2 and Ostracod formations.

Fractures are associated with both faults sets. However, the NNE-SSW fractures include regional joints and thus form the overwhelming majority. Based on core and wellbore image logs, most joints are bed bound, however larger fault associated fracture swarms appear to locally breach the basal thin shale and argillaceous beds that separate Rubble from the underlying Ostracod formation. Faults and fractures were generated during uplift. Erosion and karsting of Rubble formation due to percolating meteoric water the fault and fractures walls are etched and irregular while their apertures are widened. Furthermore, due to the strike-slip stress regime and current Zagros regional compression, many Rubble fractures and some bedding planes are critically stressed and propped open.

CUSTOMER CHALLENGE

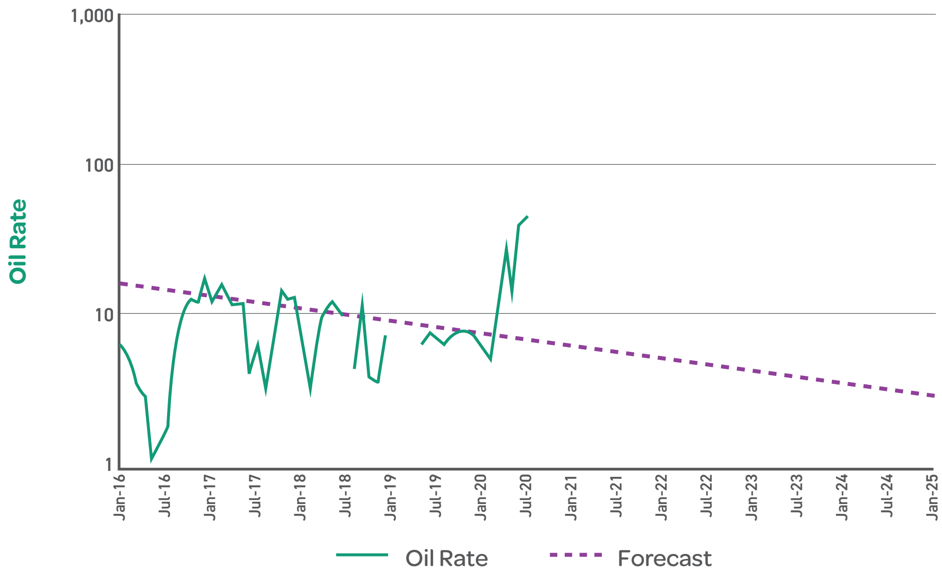
Identify an alternative, cost-effective EOR technology to increase oil production and recoverable reserves in a heavy oil carbonate reservoir
Implement EOR technology with zero CAPEX outlay
Implement EOR technology with minimal logistical and operational considerations

PILOT INJECTION PROCEDURE

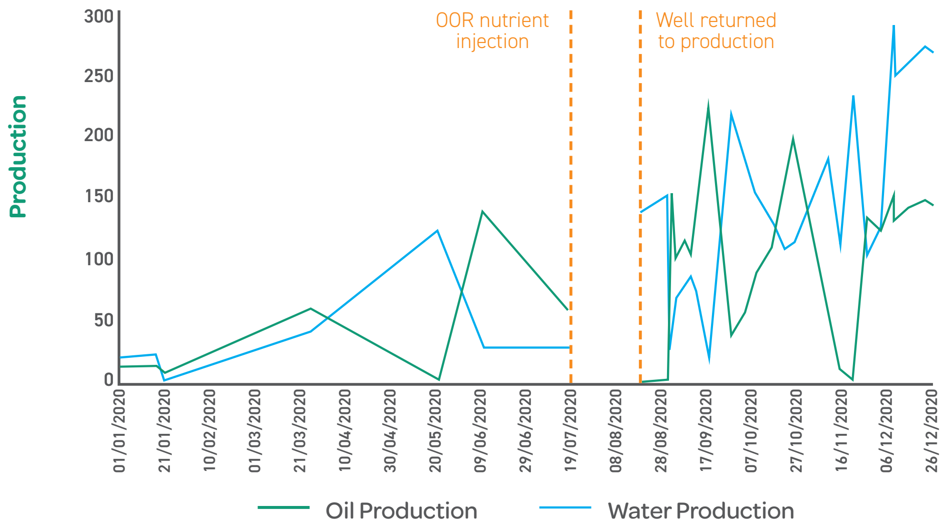
- 410 barrels of injection quality produced water and nutrient mix (>%99 water, <%1 nutrient) injected at 2 barrels/min directly at the wellhead
- Over-displacement of approximately 390 barrels of injection quality seawater at 2 barrels/min
- Shut in Well for 7 days (Incubation period)
- Second over-displacement of approximately 260 barrels of injection quality produced water at 2 barrels/min to push newly formed near well-bore ecology further into reservoir
- Shut in Well for a further incubation period of 3 days
- Return to Production

RESULTS/INCREMENTAL OIL PRODUCTION

Well (A) Oil Production Forecast



Tatweer Rubble Well (A) - Before and After OOR Treatment



WHAT OUR CUSTOMERS HAD TO SAY

> "OOR has proven to release additional trapped oil with a relatively small contact area in heavy oil."
>
> – Ammar Shaban, Tatweer Petroleum

Sockeye Field Platform Gail Offshore CA

BACKGROUND

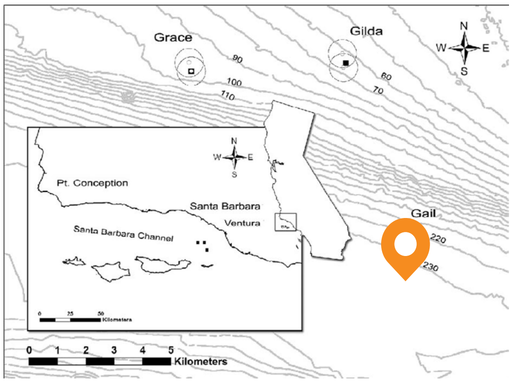
- Operator – Veneco
- Asset – Sockeye Platform
- Location – Offshore CA, USA
- Trap Type – Structural
- Pay Zone – Lower Topanga Sand
- Formation Age – Middle Miocene
- Depth – XX,XXXft
- Permeability – 0.1 to 6,500mD
- BHT – 71°C (160°F)

By Ken Lund - Flickr: Oil Platform in the Santa Barbara Channel, California

Field was discovered in 1983, sanctioned in 1990, and produced first oil in 1993.

Sockeye Field is located in the Santa Barbara Channel, Offshore California . The Sockeye Field reservoir is a broad NW-SE trending double-plunging anticline. It produces from five reservoirs; Middle and Upper Sespe Sands, Lower and Upper Topanga Sands and the Monterey formation. The field was discovered in 1970 with Platform Gail set in 739-ft of water in 1987. The Upper Topanga contains sour oil while the Lower Topanga contains light, sweet oil.

The Lower Topanga is 5' to 50' in thickness and is a poorly consolidated, high permeability sandstone with continuity across the field being fairly good.



>1,000% +
ROI*

>25,000
barrel incremental

4%
drop in water cut

< 1 week
payback

* Incremental revenue over pilot cost

CUSTOMER CHALLENGE

Identify an alternative, cost-effective EOR technology to increase oil production and recoverable reserves

Implement EOR technology with zero CAPEX outlay

Implement EOR technology with a minimal offshore footprint

PILOT INJECTION PROCEDURE

- 108 bbl treatment using 100 barrels injection water and 8 barrels of Titan nutrients
- Displace into formation with 120 barrels injection water (200% displacement volume)
- Shut in Well for 7 days (Incubation period)
- Collect flowback samples as per OOR sampling guidelines and collection daily cuts and well tests

OOR APPROACH

The application of the OOR Process® generally consists of the following steps:

Initial field screening

Well sampling and laboratory analysis

Pilot injection application

The application of the OOR pilot process for the Scott field consisted of the following steps:

Step 1 – Field Screening of Reservoir Characteristics and Well Specific Data - Completed

Step 2 – Target Well Sampling & Laboratory Analysis - Completed

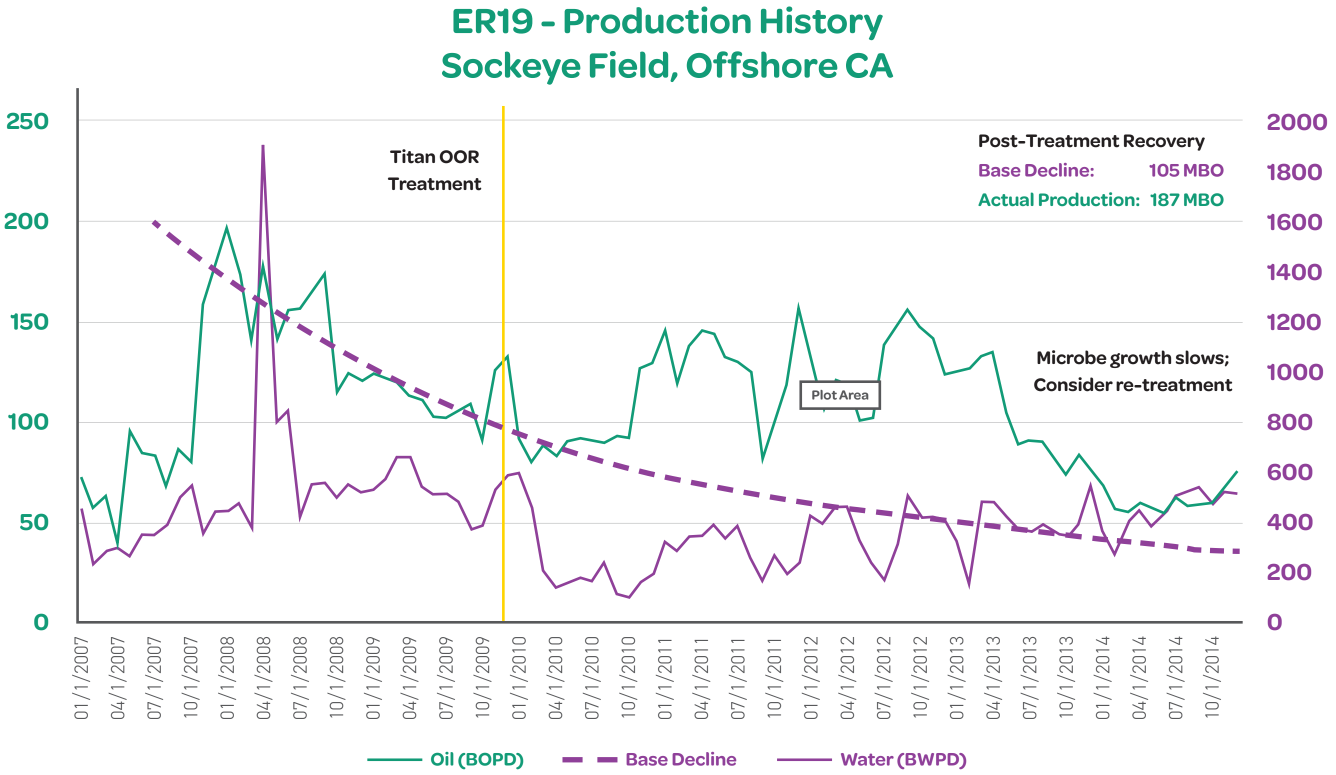
Step 3 – Precautionary small treatments to assess impact of nitrate injections

The In-Situ Microbial Response Analysis (ISMRA®) or Pilot Test is designed specifically to replicate the laboratory results in the reservoir. Produced water samples were taken pre OOR nutrient injection and just after Well flow back. A significant production response is often observed; however, the most important aspect to this step is the microbial response observed in the laboratory from samples taken upon return to production.

Step 4 – Treatment with fully formulated Titan nutrient package

Step 5 – Follow-up treatments in five Upper Topanga in offset wells

ORGANIC
OIL RECOVERY



OBSERVATIONS

- Significant Incremental Oil gain
- Lowered water cut following treatment
- No change to oil quality
- No change to separation efficacy (same oil-in-water content)

WHAT OUR CUSTOMERS SAY

"Promising results from an elegant EOR technology that can be implemented without a large offshore footprint"

– Andy Bostock, CNOOC International

"For us, it was a basic pumping operation. Very similar to a scale squeeze, although smaller volumes and therefore slightly more straightforward."

– Nigel Wallace, Altus Intervention

Organic Oil Recovery - Resident Microbial Enhanced Production Pilot in the Scott Field (UKCS)

R. Findlay[1], A. Bostock[2], C. Hill[3], C. Venske[1], M. Carroll[3]

[1] Hunting Energy Services; [2] CNOOC Petroleum Europe Ltd; [3] Titan Oil Recovery Inc

Summary

Introduction:
CNOOC has been involved in a pilot study to determine the efficacy of Organic Oil Recovery (OOR, a unique form of microbial enhanced oil recovery) as a means of maximising oil recovery from its Scott field. CNOOC's operated Scott asset came on stream in 1993 and produces crude oil and natural gas from the Scott, Telford and Rochelle fields. Scott is located approximately 188 kilometers northeast of Aberdeen in 142 meters of water.

Methods, Procedures & Process:
Organic Oil Recovery harnesses microbial life already present in an oil-bearing reservoir to improve oil recovery through changes in interfacial tension increasing the oil's mobility and improving recovery rates and reservoir wettability. These changes could increase recoverable reserves and extend field life through improved oil recovery with negligible topsides modifications. The pilot injection is implemented by injecting a specific nutrient blend directly at the wellhead with ordinary pumping equipment. The well is then shut-in for an incubation period and thereafter returned to production.

Results, Observations & Conclusions:
During initial laboratory testing of two Scott target wells the reservoir showed a diverse and abundant resident ecology which has been proven capable of undergoing the necessary characteristic changes to facilitate enhanced production. A pilot test was completed on well J17 in July 2020 and due to this application, both an ecology and production response has been proven. In addition to this response a drop in H_2S in both the Oil and Gas phase has been observed. The full method of implementation of the pilot test will also be discussed in detail and will include any challenges and/or successes in this area. The initial starting ecology of the wells will be demonstrated and compared to the ecology post-pilot. Additionally, a comparison of production and H_2S figures prior to and post the pilot implementation will be detailed. A correlation will be demonstrated between changes in ecology and an increase in production and a reduction in H_2S.

Introduction

Organic Oil Recovery (OOR) is a unique, tertiary enhanced oil recovery process. The fundamentals of the technology are based on the activation of microbial life resident in oil reservoirs with the purpose of increasing oil production. The technology can dramatically improve the mobility of oil trapped in tight pore spaces or on the oil-bearing rock to improve ultimate oil recovery.
Through batch treating with carefully defined volumes of supplemental nutrients, the process significantly increases a specific microbial population. As part of their life cycle, those targeted microbes change in state from being Hydrophilic to being Hydrophobic through a process known as nutrient limitation. This change of state results in microbes moving to the oil/water interface, temporarily reducing surface tension, releasing and mobilising significant quantities of trapped and residual oil.
Another important feature of the technology is its ability to tackle the root cause of H_2S formation by targeting specific species of microbes to outcompete Sulphate Reducing Bacteria (SRBs) which are a primary cause of this gas's formation.

Reservoir & Well Summary

CNOOC Europe's operated Scott asset came on stream in 1993 and produces crude oil and natural gas from the Scott and Telford fields. The Scott field is located approximately 188 kilometres northeast of Aberdeen in 142 metres of water. CNOOC Europe is the operating partner of Scott (41.89 %), with co-venturers MOL Operations UK Limited (21.84 %) with Dana Petroleum E&P Limited (20.64 %), Edison E&P (10.47 %) and NEO Energy Ltd (5.16 %).

The Scott field, located in the Outer Moray firth of the UK Central North Sea, is a structurally trapped Upper Jurassic reservoir. The field was discovered in 1983, sanctioned in 1990, and achieved first oil production and water injection in 1993. The Scott oil field is developed in the highly productive Upper Jurassic Humber Group sandstones of Oxfordian to Kimmeridgian age.

The Scott field is structurally complex having been separated into four main pressure isolated fault compartments by two predominant fault trends. A NE-SW trend created by the Theta graben of block 15/21, and an E-W trend created by N-S extension of the Witch ground graben.

The reservoir permeability of the Scott field is generally excellent and has been favourable for a water flooded development. The permeability ranges from 0.1 – 6,500 mD, though a typical well has a permeability of 100 – 1000 mD. The average porosity is 15 % and the average initial water saturation is 10 %.

The Scott oil field is at a depth of 10,500 – 13,500 fttvdss and was over pressured by 3,000 psi with an initial pressure of 8,500 psi. The Scott oil is light (API 34°) and undersaturated, with a producing GOR of 800 scf/stb. The original reservoir temperature was 121°C.

Over the duration of the Scott oil field development there have been > 50 production wells and > 20 water injection wells. After more than 25 years of production the oil field is in a mature stage of development with an average water cut of 90 %. There are now > 20 operating production wells, and a similar number of active injection wells.

Treated seawater is supplied to the water injection wells at a temperature of 7 – 15 °C. The bottom hole flowing temperature of the production wells is 120°C, while the flowing tubing head temperature varies between 20 and 110 °C. The variation of the flowing tubing head temperature reflects the liquid flow rate and the water cut of the individual wells rather than the reservoir temperature.

The two wells chosen for initial sampling and microbial screening were J17 and J23. J17 is a production well towards the crest of Block 1b, close to the shallowest part of the Scott field. J17 is supported by subsea injection from the East manifold and has a liquid rate of > 10,000 bpd and an average water cut of 90 %. J23 is a production well in Block 4. J23 is also supported by injection from the East manifold and has a liquid rate of <2,000 bpd and a water cut of 92 %. See Figure 1 for an outline of where both wells are located within the field.

Following laboratory analysis J17 was selected for the production well Pilot of the Organic Oil Recovery (OOR) technology. The production history of J17 is shown in Figure 2.

Prior to the Pilot implementation offshore the J17 short term production forecast was defined by CNOOC Europe. This forecast was important to ensure that a clear conclusion could be drawn on the production impact of the OOR Pilot. Ideally the well should be producing in a stable manner prior to the OOR pilot.

In the three months prior to the OOR Pilot, J17 had been supported by improved water injection, with the well production improving substantially from May 2020 to July 2020. Further changes to the J17 well performance included the water cut declining from 94 % in March 2019 to 90 % in June 2020, which when coupled with improved water injection made for the Pilot well being less stable than desired.

Flush production following shut ins is also evident in the behaviour of J17. The extent of flush production is hard to predict, though a recent example from August 2019, following a 75 day shut in, allocated the initial flush rate to be 2,200 bopd, declining to 1,200 bopd over the following two months. Figure 3 outlines the J17 short-term forecast (not accounting for flush production) prior to Pilot implementation.

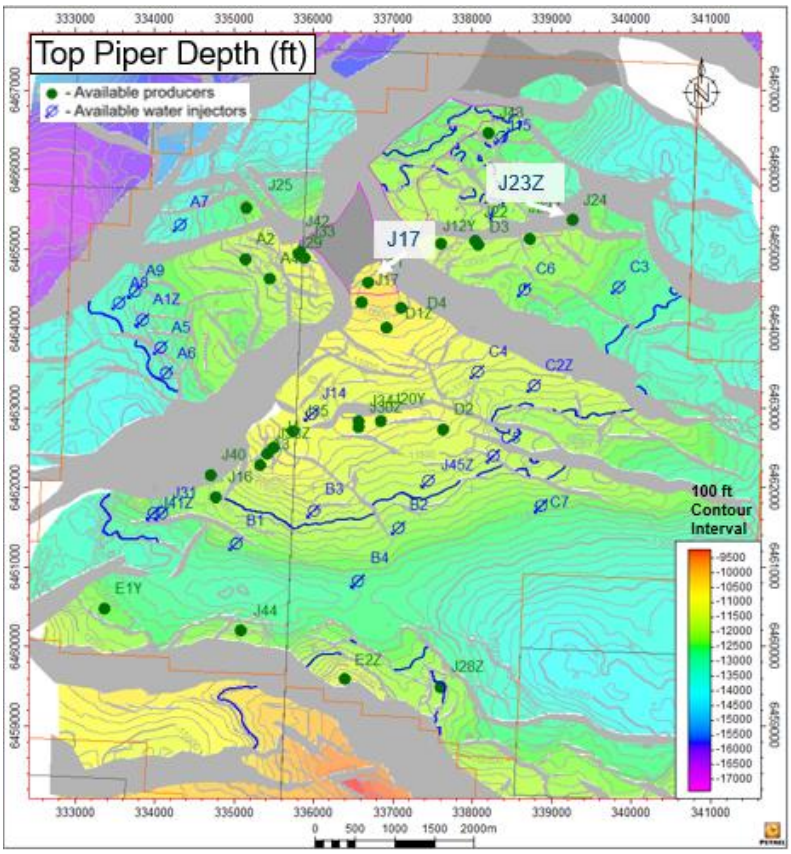


Figure 1 – Scott field map showing the location of the J17 and J23 wells. This map was created by interpreting seismic data including areas of the TGS MF10-11 survey. We would like to thank TGS for giving their permission to share this image."

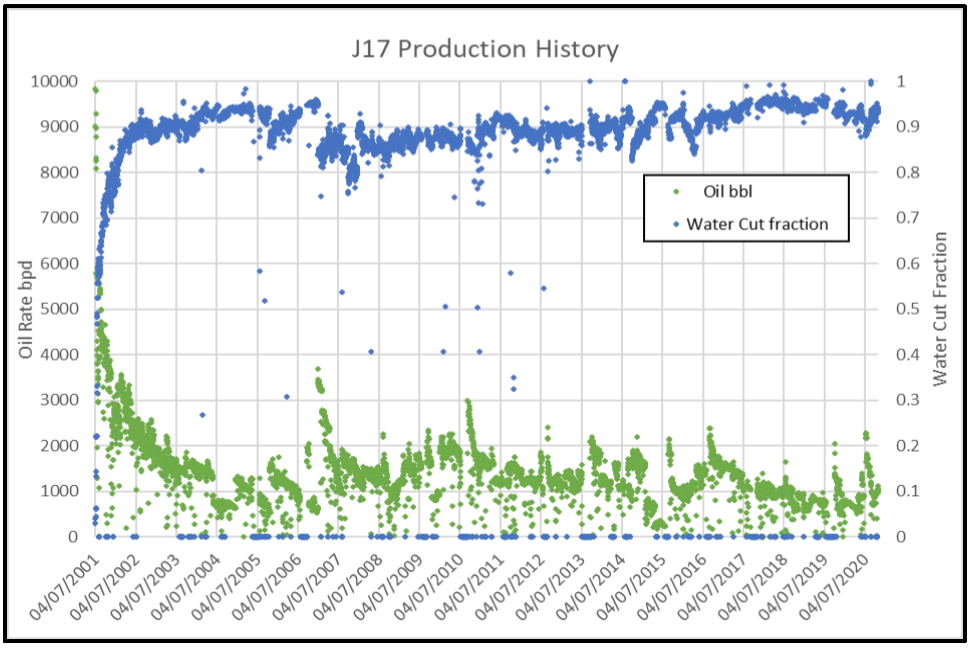


Figure 2 – J17 Production History.

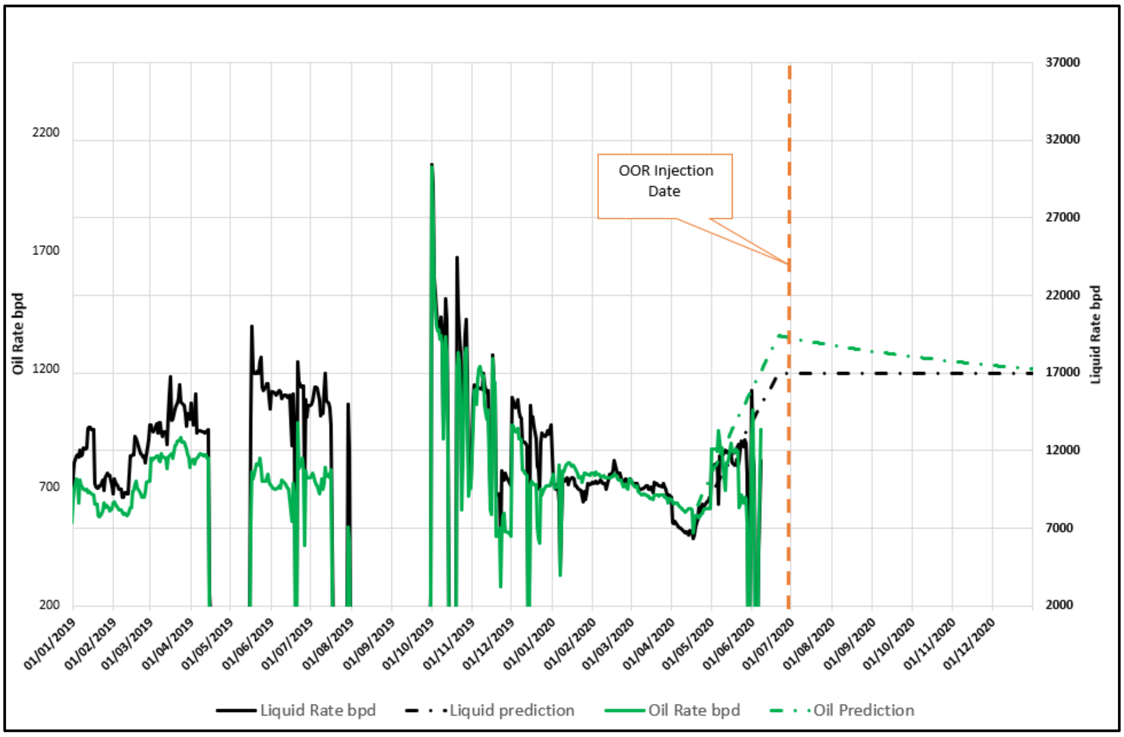


Figure 3 – J17 short term forecast without an OOR Pilot treatment (without flush production impact).

Field Screening & Initial Laboratory Work

Initial OOR technology screening of CNOOC's Scott field was completed in early 2018. Reservoir and well technical details were reviewed against OOR's defined technical criteria to determine the suitability of the reservoir for OOR technology application. Parameters such as oil gravity, reservoir temperature, water salinity, water pH and reservoir permeability were closely considered. A summary of the main parameters aligned to the OOR guidance criteria is detailed below in Table 1.

Screening criteria	Scott Field	OOR technical criteria
Oil Gravity (API)	35	12 – 42
Produced Water pH	6.7	6 - 8
Reservoir Temperature (ºC)	121*	<105
Produced Water Salinity (TDS)	134,000	<215,000
Reservoir Permeability (mD)	500	> 1

Table 1 - Summary of Scott screening criteria. *Due to water injection history reservoir temperature was thought to have cooled sufficiently to support suitable microbial ecology.

Following positive field screening results produced water samples were collected from the well heads of J17 and J23 on the 25th and 29th August 2018. For each well, 2 litres were required to be collected and sealed in four (4) 500 ml bottles. These were then taken onshore by helicopter and then sent via DHL Express to the Titan laboratory in Monrovia, California for analysis and growth studies.

Figure 4 - J17 Scott sample bottles.

Upon arrival at the Titan laboratory two (2) bottles of each well sample were sent to a separate genomics laboratory for DNA and RNA sequencing analysis to identify the microbial ecology present.

Within the Titan laboratory spin and stains were completed on samples from the remaining two (2) bottles to assess whether living microbes were present. After the spin and stain the remaining fluid was taken through a thermal reactivation process by raising the temperature from 35 ˚C measured on arrival gradually over time for 3 to 4 days until the sample reached the minimum reservoir temperature of 74 ˚C. One bottle was carefully agitated in case any microbes had settled out and then individual samples were taken from this fluid to fill 10 tubes. Each of these tubes contained different OOR Process nutrient combinations and concentrations as well as 1 tube containing only sampled produced water as a control.

The top of each tube was flushed with 100 % nitrogen to exclude as much oxygen as possible. These tubes were then incubated at 65 and 75 ˚C in a dry and dark incubator. Every 3 to 4 days the tubes were examined for any growth (usually seen as a gradual increase in turbidity or opacity). A little growth was observed after 3 weeks in the samples at 75 ˚C and a little more after 4 weeks of incubation. At this point samples were taken from the tubes which exhibited this growth, smeared on slides, fixed and then stained by the Grams differential method with slight variations due to the expected types of microbes. After staining and drying the slides were then examined under a high-power digital imaging microscope for abundance, type and morphology of microbes present and thereafter representative images were taken for documentation and later use for comparison post any Pilot Test (In-Situ Microbial Response Analysis (ISMRA)). In Table 2 laboratory results are shown from well J17 which demonstrate the microbial ecology present, and which was needed to support progression of the Pilot test in the field.

<table>
<tr><td>Clear</td><td>Slightly Hazy</td><td>Lightly Hazy</td><td>Hazy</td><td>Slightly Cloudy</td><td>Lightly Cloudy</td><td>Moderately Cloudy</td><td>Cloudy</td><td>Very Cloudy</td></tr>
<tr><td colspan="3">Field Name:</td><td colspan="6">Scott</td></tr>
<tr><td colspan="3">Well Number:</td><td colspan="6">J17</td></tr>
<tr><td colspan="3">Incubation Details:</td><td colspan="6">Incubated at 75 °C</td></tr>
<tr><td colspan="3">Notes on Entire Set: (Smells, Sediments, Colors)</td><td colspan="6">Tubes had a slight amount of preciptate at the beginning, very little color and almost no oil</td></tr>
</table>

Tube	Contents	Tube Observations	
		October 1st, 2018	*October 22nd, 2018*
1	No Nutrients	Clear	Clear
2	1ml control Bacteria	N/A	-
3	1X Nutrients	Clear	Very lightly cloudy
4	0.1X Nutrients	Clear	Clear
5	2X Nutrients	Clear	Lightly cloudy
6	No Alpha	Clear	Very lightly cloudy
7	No Beta and Alpha	Clear	Clear
8	No Zeta and Alpha	Clear	Clear
9	No Zeta	Clear	Clear
10	No Beta	Clear	Clear

The designations in Greek letters in the above table stand for various components of the nutrient recipe that are excluded in that test tube.

Staining performed on 23-10-2018

Slide	Slide Observations	
1	+	+ few ++ more than a few +++ some to many
2	**N/A**	
3	**+ to ++**	
4	+	
5	**+ to ++**	
6	**+ to ++**	
7	+	
8	+	
9	+	
10	+	

Table 2 **-** Growth observation in full work up tubes.

Imaging Studies J17

In addition to the number of microbes, the type and the morphology are also reviewed. In the partial image in Figure 5 below an image of the microbes found in the produced water sample is shown that was labelled Tube 1 – Control, no nutrient supplementation.

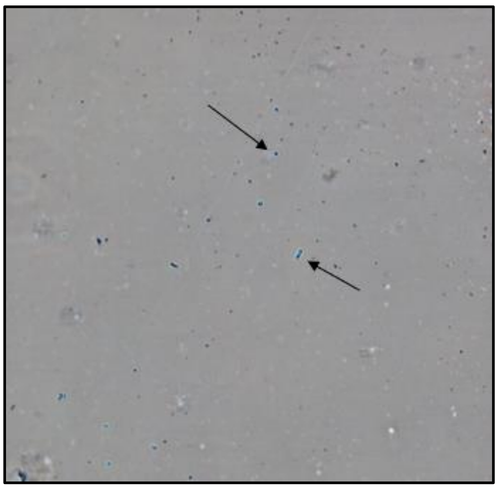


Figure 5. High resolution image of Tube 1 control sample (partial image) shows very few microbes present of both rod and cocci (circular) type and mostly gram positive. Arrows point to examples of the microbes.

Of the other tubes some growth was observed as shown within the partial image in Figure 6 below.

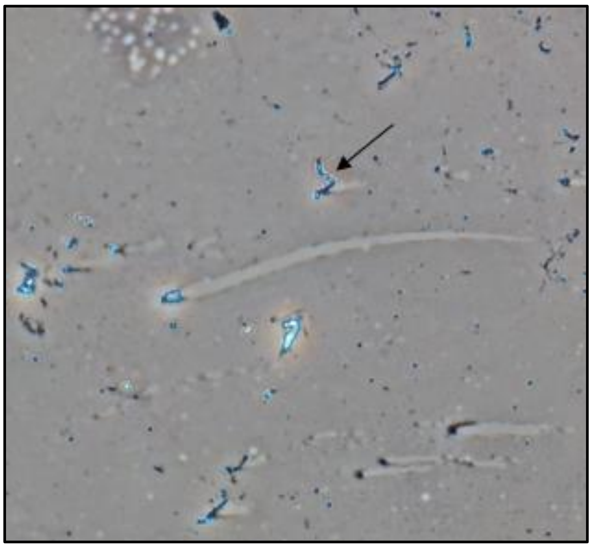


Figure 6. Stained sample from a Tube containing a low level of a typical OOR nutrient combination (partial image). There has been an increase in microbe number with some exhibiting morphological changes associated with the activation that denotes a possible positive result. The arrow indicates rods now in groups known as "chains". Both rods and cocci increased.
The increase in microbe concentration in some tubes are typical of a positive response and indicate there were living extremophiles present in the samples collected that grew at 75 ˚C and have been activated and stimulated to grow in the laboratory study.

Genetic Analysis for Sample J17

- Two liquid samples were received on 15th Sept 2018
- 16S quantification was performed by 16S qPCR
- Archaeal and Bacterial populations of all samples were analysed in parallel by 16s metagenomic sequencing, using MiSeq platform
- This approach robustly detects both bacteria and archaea

There was a diverse presence of microbes including some that grow at surface temperatures between 25 ˚C and 40 ˚C and are not considered extremophiles. These were likely to be contamination from the upper well bore piping or near the spigot where the sample was taken from. However, as shown in the pie chart in Figure 7 below approximately 75 % of the microbes were anaerobic which can grow at higher temperatures. However, the microbes present included many Sulphate-reducing bacteria (SRB) and Nitrite reducing sulfide oxidizing bacteria (NRSOB) species. There was one species of Archaea that is known to be a hyperthermophile capable of growing in temperatures in excess of 100 ˚C. There are some species present that will respond to the OOR Process. Most of these, grow between 65 ˚C and 85 ˚C. Finding microbes that grow in a variety of extremophile temperature ranges indicates that due to the many years of water flood with low temperature water (approximately 7-15 ˚C) there are areas in the reservoir that have temperatures below the temperature originally observed.

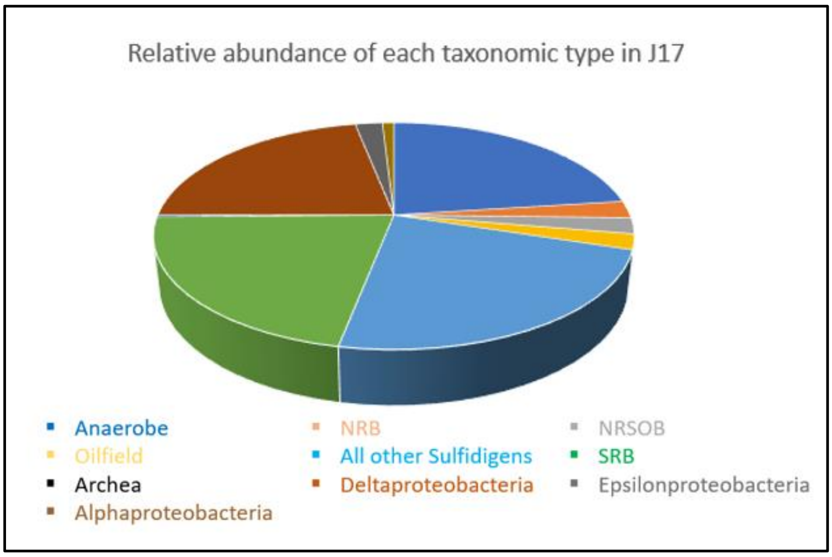


Figure 7 **-** Chart of relative abundance of each taxonomic type (based on percent presence) for well J17.

No details of the laboratory analysis for well J23 is included within this paper however it was similar to the J17 study. For a number of technical and operational reasons J17 was chosen to progress the Pilot.

Field Application

Following successful laboratory analysis and microbial evidence which showed that resident microbiology within both wells J17 & J23 could be activated by OOR nutrient a Pilot test was initiated within well J17 in June 2020. The Pilot is typically applied in a single producing well to test a relatively small volume of the nutrient formulation created from the initial laboratory work described in the previous section.

Rigging Up, Treatment Preparation & Mixing

A closed line hard piping system was constructed offshore on Scott to allow for a surface water injection line to be suitably connected to well J17. This system ensured that both water injection and the dosed nutrient could be safely and compliantly introduced to the producing well. A suitable system was already designed and in place for a Scale Squeeze campaign on Scott and this system needed only small modifications to make it suitable to be used for the OOR Pilot (see Figure 8).

Figure 8 – Scott J17 OOR Pilot hard piping system.

3,480 litres of concentrated nutrient and 1,000 litres of de-ionised water was supplied offshore in five (5) partially filled 1 m^3 Intermediate Bulk Containers (IBCs). All applicable chemical treatments which were being applied to either the producing well, the water injection line or water injection fluid, such as oxygen scavenger and corrosion inhibitor, were suspended for the duration of the pumping and shut in period.

A pre-injection produced water sample was collected from the J17 wellhead prior to the well being shut-in before treatment. The nutrient and the de-ionised water were then closed line circulated together for 15 minutes to ensure the overall fluid volume of 4,480 litres was thoroughly mixed and evenly divided between each of the five (5) IBCs.

To ensure that there was no contamination from any residual chemicals or other fluids or particulates, prior to any mixing or pumping all flow lines were flushed with injection quality seawater.

Treatment Pumping

At 10:26 am on the 28th June 2020 the 4,480 litres of diluted nutrient were dosed/spiked across 2,435 barrels (387,100 litres) of injection quality water which was free from scale inhibitor and biocide using a pressure pump. The average rate of this dosing for the full 13 hours of nutrient injection was 4 litres/minute. The injection rate into well J17 was initially set to 0.99 barrels per minute (bpm) until the tubing was full at a volume of 241 barrels after approximately 4 hours of pumping. At this point the injection rate was increased to 3.96 bpm for the remaining 9 hours of injection. During the entire duration of pumping the main treatment pressure within the well did not exceed 1800 psi. This was below the maximum stated treatment pressure on the well of 4,265 psi set by CNOOC Europe. (See Figure 9 for an outline of the Pilot equipment and positioning.)

Figure 9 – Scott J17 OOR Pilot treatment equipment lay-down area.

First Displacement – Post Treatment

To ensure that the nutrients injected were pushed out into the formation the first of two over displacements of injection quality seawater was applied. This injection consisted of 411 barrels (67,400 litres) pumped at a rate of 4 bpm. This injection equated to 150 % of the tubing volume and took approximately 1 and 3/4 hours to complete with the maximum pressure within the well not exceeding 1800 psi. After the injection was complete all lines were bled down, and the well was shut-in for a period of 7 days at 02:00 on the 29th June 2020.

Second Displacement - Post Treatment

To allow for the increased and activated population of resident microbiology to be pushed further out from the wellbore, a second over displacement of injection quality seawater was initiated at 02:00 on the 6th July. This injection consisted of 1,000 barrels (164,000 litres) pumped at a rate of 4 bpm. The pressure within the well during the second displacement initially reached 2,300 psi however over time and at the end of the pumping period this pressure had gradually dropped to 950 psi. After the injection was complete all lines were bled down and J17 was shut-in for a period of 3 further days at 06:50 on the 6th July 2020.

Well Restart

After the three-day shut-in period was completed the well was brought back onto production on the 9th July at 06:00. To help minimise the expected effect to the resident downhole ecology of bringing such a large well back into full service quickly, flow was brought back gradually through production choking. The production choking schedule completed offshore is outlined within Table 3.

Date	Production Choke
9th July 2020	25%
10th July 2020	50%
11th July 2020	50%
12th July 2020	50%
13th July 2020	100%

Table 3 **-** Return well to production choking schedule.

Post Pilot Microbial/Production Response

To understand the microbial response from the Pilot, water samples were taken daily, weekly and then monthly thereafter. The sampling schedule completed on Scott is outlined within Table 4 with each 'sample' consisting of four (4) x 500ml bottles of J17 produced water.

Date	Sample # & Day from Injection
28th June 2020	Pre-treatment sample
9th July	Sample #1 – 3 hours after restart
9th July	Sample #2 – 7.5 hours after restart
9th July	Sample #3 – 12 hours after restart
10th July	Sample #4
13th July	Sample #5
15th July	Sample #6
23rd July	Sample #7
30th July	Sample #8
6th Aug	Sample #9
13th Aug	Sample #10
20th Aug	Sample #11
8th Sept	Sample #12A
20th Sept	Sample #12B
1st Oct	Sample #13

Table 4 – Post Pilot produced water sampling schedule.

Each sample was analysed in the Titan laboratory where the microbe content was assessed both for abundance and evidence of activation using a staining and imaging technique and a limited growth analysis to be sure the microbes were living. Figure 10 shows an example of an image from Sample #2 (7.5 hours after well restart).

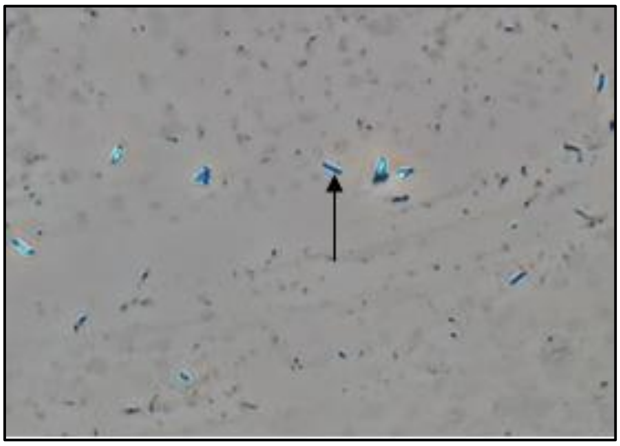


Figure 10 - Image from Sample #2 staining showing activated microbes. The arrow points to a short chain of rod-shaped microbes.

The laboratory image outlined in Figure 10 indicates that there were numerous microbes present, numbering approximately 3.2 million per ml. The pre-treatment sample had approximately 930,000 microbes per ml indicating a significant increase in the microbial population resulting from the treatment process.

In Table 5, an estimate of the microbes per ml in each sample is given to provide an overview of how the OOR Process has worked over-time post Pilot injection. The microbial populations from each post Pilot sample were calculated by using the microns per pixel of the laboratory microscope images extrapolated from the known volume of liquid placed on the slide aligned to the area over which the fluid is spread. The resulting number is accurate as regards the slide but may vary by up to a magnitude in the actual sample due to the small volume taken. The sample itself taken from the well is also small in comparison to the total water produced from the well each day. Nevertheless, if microbes in the millions are found post OOR treatment, it is a strong indication that the OOR Process has taken effect.

Sample #	Microbe count in field	Microbe count/ml	Notes / Observations
2018 sample 25-10-2018	12	750,000	Very, very few gram-positive rods and very few gram-positive cocci
2020 sample 26-04-2020	16	1,000,000	Very few gram-positive rods and very few gram-positive cocci.
Pre-treatment	15	930,000	Very, very few gram-positive rods and very few gram-positive cocci
1	26	1,625,000	Very few gram-positive rods and very few to a few gram-positive cocci, with very few in chains present
2	52	3,250,000	A few to more than a few gram-positive rods and a few gram-positive cocci, with very few to a few in short chains present
3	187	11,684,500	Very few to a few gram-positive rods and some to many gram-positive cocci, with very few to a few in short chains present
4	25	1,562,500	Very few to a few gram-positive rods and very few to a few gram-positive cocci, with very few in chains present
5	119	7,437,500	Very few gram-positive rods and some gram-positive cocci, with very few in chains present
6	114	7,125,000	Very few gram-positive rods and some gram-positive cocci, with very few in short chains present

7	48	3,000,000	Very few gram-positive rods and more than a few to some gram-positive cocci, with very few in chains present
8	33	2,062,500	Very few gram-positive rods and more than a few gram-positive cocci, with very few in chains present
9	37	23,125,000	Very few gram-positive rods and more than a few gram-positive cocci, with very few in chains present
10	48	3,000,000	Few gram-positive rods and few gram-positive cocci, with a few short chains
11	47	2,937,000	Few gram-positive rods and more than a few gram-positive cocci, with a few in chains
12A	187	11,687,500	Few to more than a few gram-positive rods and more than a few gram-positive cocci, few in short chains
12B	22	1,375,000	Very few gram-positive rods and very few gram-positive cocci, a few in chains
13	53	3,312,000	Few gram-positive rods and few gram-positive cocci, few in short chains

***Table* 5**– Post Pilot produced water microbial populations (from slide counts).

The pre-treatment sample taken had approximately 930,000 microbes per ml. This population was similar to the numbers measured within the original produced water samples taken in October 2018 and April 2020 to determine if this well was suitable for the OOR Process (see the first three entries of Table 5 on the previous page).

All the samples taken after the Pilot Test treatment and shut-in period had more microbes per ml than the pre-treatment sample. The presence of microbes increased with time for the first few samples and then began to drop off for a few days followed by a further increase in microbes towards the end of the sample period being reviewed. This is very typical of the OOR response as there is a first bloom of microbes followed by a die off as the nutrients move away from the well-bore, followed by a new wave of microbe growth and subsequent further die off. The nature of the sampling process provides a moment in time of the reservoir ecology and thus should be seen as indicative.

In addition to the population increase there was also a clear increase in microbes which indicated a response to the OOR Process, where the nature or the microbe changes from being Hydrophilic to being Hydrophobic through nutrient limitation. The maximum number of microbes seen in this series was more than 20-fold higher than the pre-treatment sample.

Within the sampling timeline, due to operational requirements water injection was turned off. The corresponding water samples showed a sharp drop in microbes per ml. Once water injection re-start had been completed microbial numbers had recovered to a certain extent. This may indicate that temperature changes in the oil-bearing structure due to the changes in injection water flow (injected water ranges from between 7 to 15 °C) have direct effects on the microbial ecology.

Following well J17's production re-start on the 9th July, a program of well testing was completed. Well tests on Scott are completed through connecting each individual well to the assets test separator. Seven (7) individual well tests of varying lengths were completed at planned intervals and the results are shown in Table 6. The first well test took place on the 14th July, 5 days after the well was re-started. This first test date was planned to both allow for the well's production choke to be fully open at 100 % and to also allow shut-in flush production to have mostly diminished. Through analysis of all the past production shut-ins of J17 it was calculated that 1,000 barrels of the oil produced by J17 following the OOR treatment should be described as flush production due to the shut-in process.

Test date	**Duration**	**Water Cut**	**Oil**	**Water**	**Liq. Rate**	**Injection volume - average rate for previous week**	**H_2S Oil**		**H_2S Gas**
	(Hr)	(%)	(bpd)	(bpd)	(bpd)	(bpd)	ppmw		ppmv
31-Jan-20	14	90.6	740	7,160	7,900	12,434	6.57		212.88
11-Feb-20	24	90.7	758	7,348	8,106	11,530	9.32		266
18-May-20	13	90.1	1,014	9,269	10,283	42,175	13.32		149.23
24-May-20	11	89.9	1,102	9,835	10,937	46,697	13.83		146.84
13-Jun-20	13	89.6	1,513	13,020	14,533	0	6.05		163.86
25-Jun-20	24	90.1	1,171	10,695	11,866	3,444	5.42		151.89
28-Jun-20		Pilot Nutrient Injection							
09-July-20		Well re-start							
14-Jul-20	17	86.8	2,358	15,505	17,863	39,714	5.06		171.15
21-Jul-20	18	87.9	1,915	13,944	15,859	39,211	4.81		162.6
02-Aug-20	14	88.8	1,712	13,594	15,306	37,349	4.85		94.25
10-Aug-20	13	89.2	1,690	13,929	15,619	36,909	3.3		103.45
19-Aug-20	16	89.9	1,561	13,883	15,444	0	4.91		87.91
24-Sep-20	12	90.5	1,158	10,990	12,148	10,419	3.23		103.45
29-Sep-20	14	90.2	1,075	9,933	11,008	9,077	3.81		93.41

Table 6 – J17 Well Tests pre and post treatment.

The first well test completed on the 14th July measured on average oil production rate of 2,358 barrels per day (bpd) with a total liquid rate of 17,863 bpd. The oil production rate was the highest tested rate for five years. Water cut within the first well test was measured at an average of 86.9 % which again was the lowest tested within a period of 5 years. Subsequent well test measurements also show that the H_2S concentrations in both the Oil and Gas phase had significantly reduced.

The reduction in H_2S concentration was not evident in the first two well tests following the trial, however the reduction has been seen in all subsequent tests and has been sustained up to the date of writing of this paper. The OOR Process is designed to encourage growth of microbes that do not form H_2S. This has the effect of out competing the Sulphur reducing microbes present (SRBs) as they normally use Sulphur as an energy source. It takes SRBs sometime to switch to another energy source, if they can do it all. It is this difference in metabolism that gives the competitive edge to the desired microbes. The large growth of microbes which do not form H_2S essentially use up the limiting nutrients before the SRBs can proliferate. The result of this process is often a decline in SRB population. However, since these microbes are the source of the H_2S, there is often already H_2S dissolved in the water and oil which will take some time for that to be produced at the well head. The effect will begin to be seen when the lack of replenishment from the declining SRBs causes a gradual decline in produced H_2S that can fall as much as 50 % and remain at that level for an extended period of time.

Analysing the post treatment well test numbers against the pre-treatment forecast, as seen in Figure 11, it can be cautiously interpreted as showing a response in the production. This response persisted for more than a month from well re-start. Similarly, the well test water cut of the fluid showed significant change following OOR treatment, shown in Figure 12 on the following page. When these numbers are considered against the laboratory results, particularly the microbial population outlined within Table 4, they point to a potential correlation between the production and microbial response.

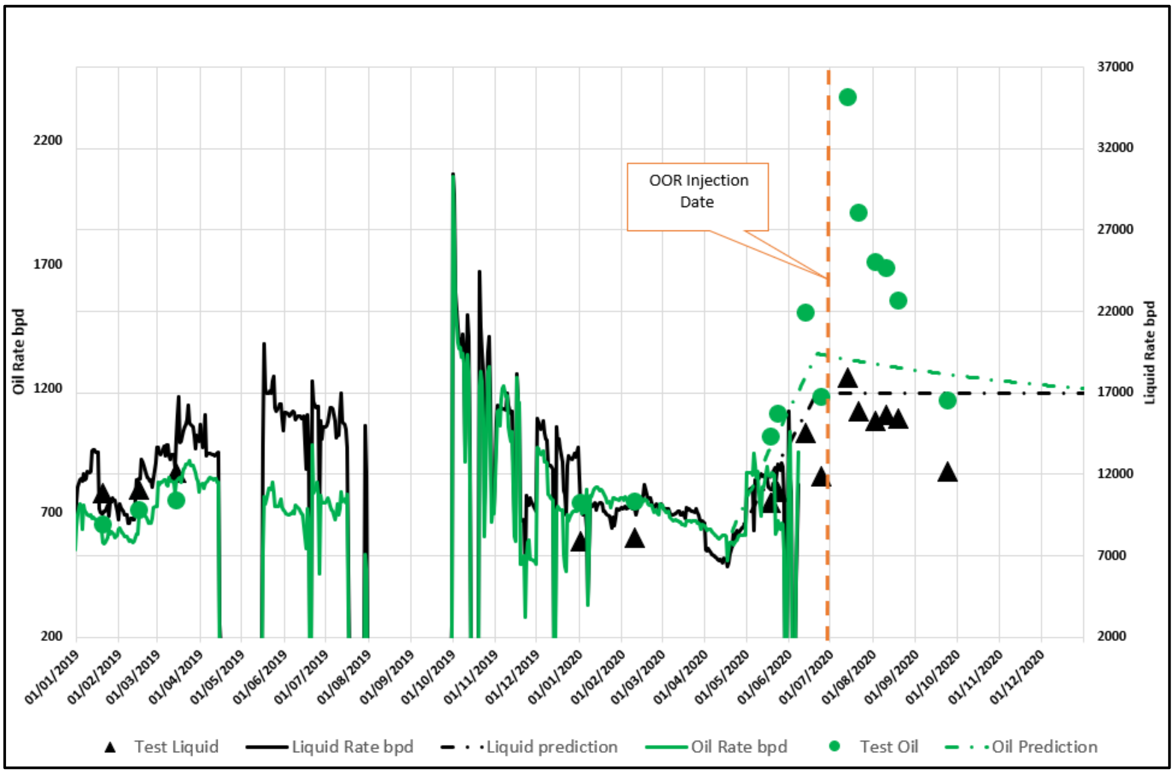


Figure 11 – Comparison of OOR Pilot treatment results against the pre-treatment forecast.

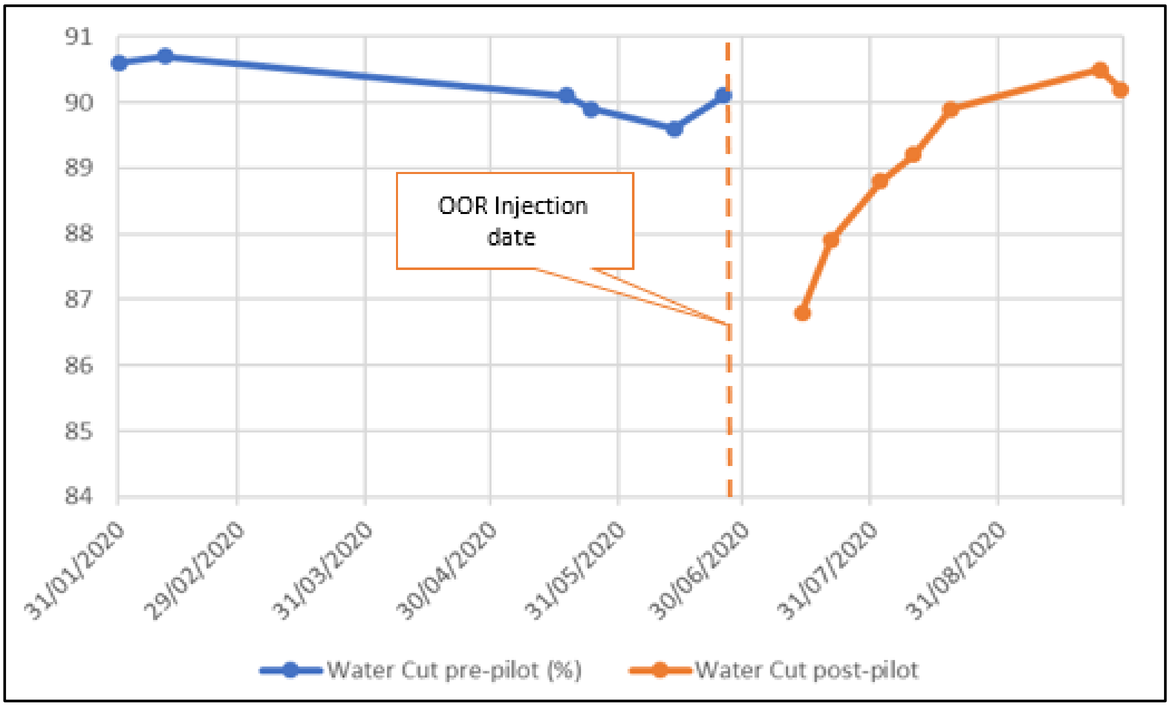


Figure 12 – J17 well test water cut.

Conclusions

During the initial laboratory testing of well J17 the reservoir showed a diverse and abundant resident ecology which has been assessed, through the application of an OOR Pilot test, of being capable of undergoing the necessary characteristic changes to facilitate enhanced production. The Pilot test results demonstrated a strong microbial and encouraging production response, which potentially demonstrates that Organic Oil Recovery technology may be successfully applied to large offshore producing wells. The proof of this application may only arrive following an injector producer field trial. A correlation between the microbial and production responses has been implied through the mapping of microbial population growth and microbial nutrient limitation against the predicted production response.

In addition to this response, a drop in the concentration of H_2S in both the Oil and Gas phase was observed. Due to the volumes involved in the Pilot Test phase it was thought unlikely that a significant drop in both phases would be seen, however this effect continued for some months post injection. There is also evidence in the form of well test measurements supported by laboratory analysis which suggests that this effect continues to persist. Further studies and nutrient formulations will be considered for wider application of the technology on Scott to assess its ability to manage H_2S production at source.

Due to the results of the pilot test a wider technology application on Scott targeting water injection and supported wells is being considered. The ability of the injected nutrient to affect as large a part of the reservoir as possible, and thus the resultant resident ecology, increases the chance of a larger and more sustained production response.

Acknowledgments

We thank Altus Intervention Ltd for their effective offshore well intervention work on Scott, during the Pilot. Finally, we would like to thank CNOOC Europe, the operating partner of Scott and its co-venture partners MOL Operations UK Limited, Dana Petroleum E&P Limited, Edison E&P and NEO Energy Ltd.

SPE-204884-MS

Organic Oil Recovery - Resident Microbial Enhanced Production Pilot in Bahrain

Christopher Venske, Hunting – Organic Oil Recovery; Ali Mohamed, Ammar Shaban, and Nelson Maan, Tatweer Petroleum; Dr. Colin Hill and Michael Carroll, Titan Oil Recovery; Roger Findlay, Hunting – Organic Oil Recovery

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Abstract

Tatweer Petroleum has been involved in a Pilot study to determine the efficacy of Organic Oil Recovery (OOR), a unique form of microbial enhanced oil recovery as a means of maximising oil recovery from its Rubble reservoir within the Awali field.

OOR harnesses microbial life already present in an oil-bearing reservoir to improve oil recovery through changes in interfacial tensions, which in the case of Rubble will increase the heavy oil's mobility and improve recovery rates and reservoir wettability. These changes could increase recoverable reserves and extend field life through improved oil recovery with negligible topsides modifications. The Pilot injection is implemented by injecting a specific nutrient blend directly at the wellhead with ordinary pumping equipment. The well is then shut-in for an incubation period and thereafter returned to production.

In Tatweer Petroleum's Awali field the Rubble reservoir is one of the shallowest oil reservoirs in the Bahrain and the first oil discovery in the Gulf Cooperation Council (GCC) region. The reservoir can be found at depths of around 1400 – 1900 ft. During initial laboratory testing of the Rubble target wells the reservoir showed a diverse and abundant resident ecology which has been proven capable of undergoing the necessary characteristic changes to facilitate enhanced production from the target wells. The Pilot test on one of these wells, called Well (A) within this paper, took place in July 2020 and due to this process, the ecology of this well showed these same changes in characteristics in the reservoir along with an associated oil response. The full method of implementation of the Pilot test will also be discussed in detail and will include any challenges and/or successes in this area. The initial state ecology reports of Well (A) are demonstrated and compared to that of post-Pilot test ecology. We also present the production figures for the well prior to and post the Pilot implementation. A correlation will be demonstrated between changes in ecology and an increase in production.

Reservoir Summary

The Awali field contains multiple stacked oil & gas reservoirs within a faulted north-south trending anticline. It is assumed that all reservoirs are charged from the same deep source or sources via sequential vertical migration during periods of tectonic compression that generated and reactivated faults. Although similarly sourced, the crude properties gradually change with depth. Dry and wet gas filled the deep Khuff formation whereas highly viscous crude and bitumen charged the Aruma formation at 500 feet depth.

In the Mishrif formation (locally know as Rubble) underlying the Aruma, the oil properties vary laterally across the structure. It is estimated that only 10% of Original Oil in Place (OOIP) to be light oil (20 to 30 API) mainly concentrated in the east and northeast flank of the reservoir, whereas the remaining 90% is classified as heavy oil (below 18 API). The gravity significantly decreases heading south until it reaches 12 API with viscosities reaching 400 cP. The current average reservoir pressure is estimated around 300 psia (initially 600 – 700 psia) and temperature is ~120° F. The initial solution GOR is 28 scf/bbl and bubble point pressure is 316 psia. Water salinity is around 80,000 to 100,000 ppm NaCl.

The Rubble reservoir has been historically considered as secondary target for higher potential deeper reservoirs, as wellbores were salvaged from underlying formations to Rubble. When Tatweer Petroleum was founded in 2009, a dedicated development plan was put together with the aim of further developing the Rubble formation. The plan includes an intense drilling program in the east and northeast flank. Additionally, a gas injection pilot has been planned and executed to provide a pressure support program in the depleted fault blocks. In order to exploit the majority of the OOIP which is classified as heavy oil, several thermal pilot pads have been drilled and executed since 2011 in different areas of the formation. Cyclic steam stimulation (CSS) has worked well in the selected areas of Rubble, recovering potentially 10% of the OOIP within the pilot area. As CSS recoveries in similar reservoirs typically only reach 15% OOIP, alternative methods (including non-thermal) with higher potential recovery are being considered.

In Bahrain the late Cretaceous Mishrif formation is known as the (Rubble) limestone. Its name reflects its abuse by extensive erosion, karsting, faulting and fracturing. Two dominant fault sets exist, both associated with Late Cretaceous regional compressional events. NNE-SSW relaying faults dominant the axis of the anticline, whereas later NW-SE trending strike-slip wrench faults cut across the field, but most prominent on the structural flanks. Both fault sets extend below the Rubble, passing through the underlying LS2 and Ostracod formations.

Fractures are associated with both faults sets. However, the NNE-SSW fractures include regional joints and thus form the overwhelming majority. Based on core and wellbore image logs, most joints are bed bound, however larger fault associated fracture swarms appear to locally breach the basal thin shale and argillaceous beds that separate Rubble from the underlying Ostracod formation. Faults and fractures were generated during uplift. Erosion and karsting of Rubble formation due to percolating meteoric water the fault and fractures walls are etched and irregular while their apertures are widened. Furthermore, due to the strike-slip stress regime and current Zagros regional compression, many Rubble fractures and some bedding planes are critically stressed and propped open.

Well (A), was chosen for initial sampling and microbial screening. The Rubble field map showing the position of Well (A) is shown in Figure 1. Following laboratory analysis this well was selected for a production well Pilot of the Organic Oil Recovery (OOR) technology. The production history of Well (A) is shown in Figure 2.

Figure 1—Rubble field map showing the location of all wells.

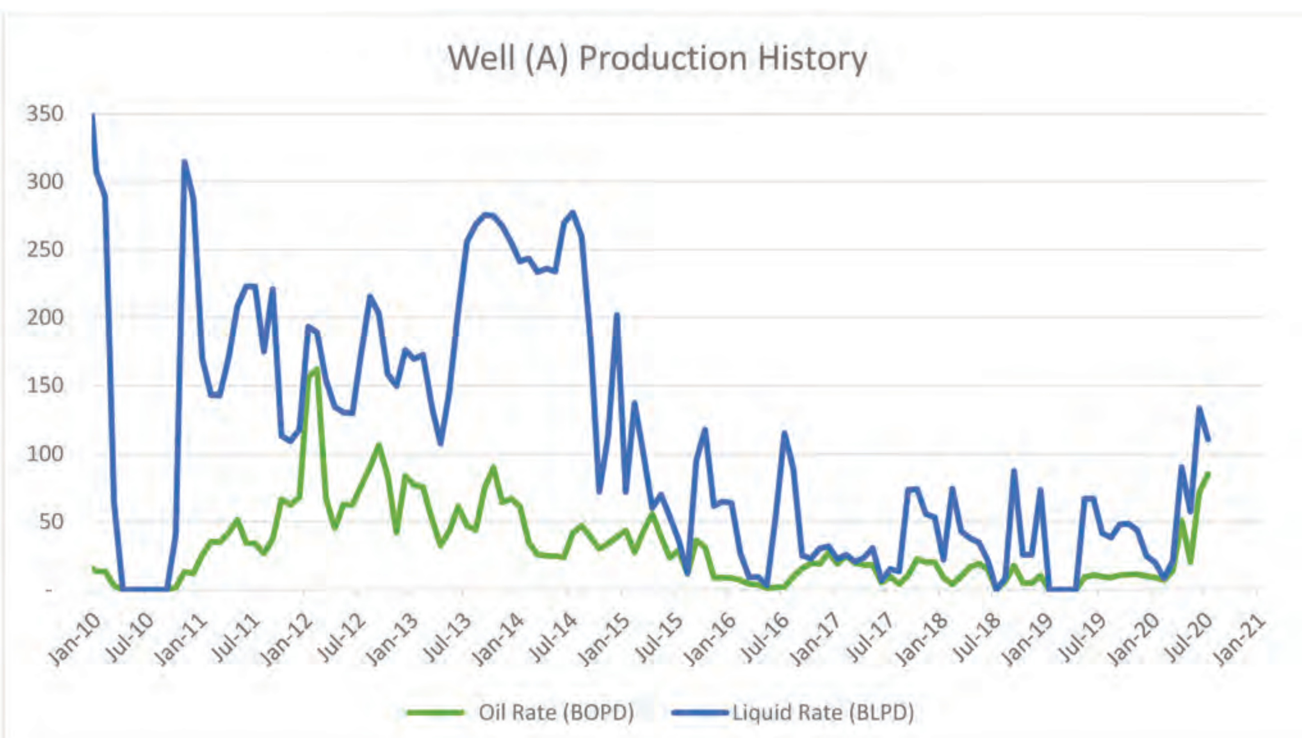

Figure 2—Well (A) Production History (2010 – 2020).

Prior to the Pilot implementation Well (A) short term production forecast was defined by Tatweer. This forecast was important to ensure that a clear conclusion could be drawn on the production impact of the OOR Pilot. Ideally the well should be producing in a stable manner prior to the OOR Pilot.

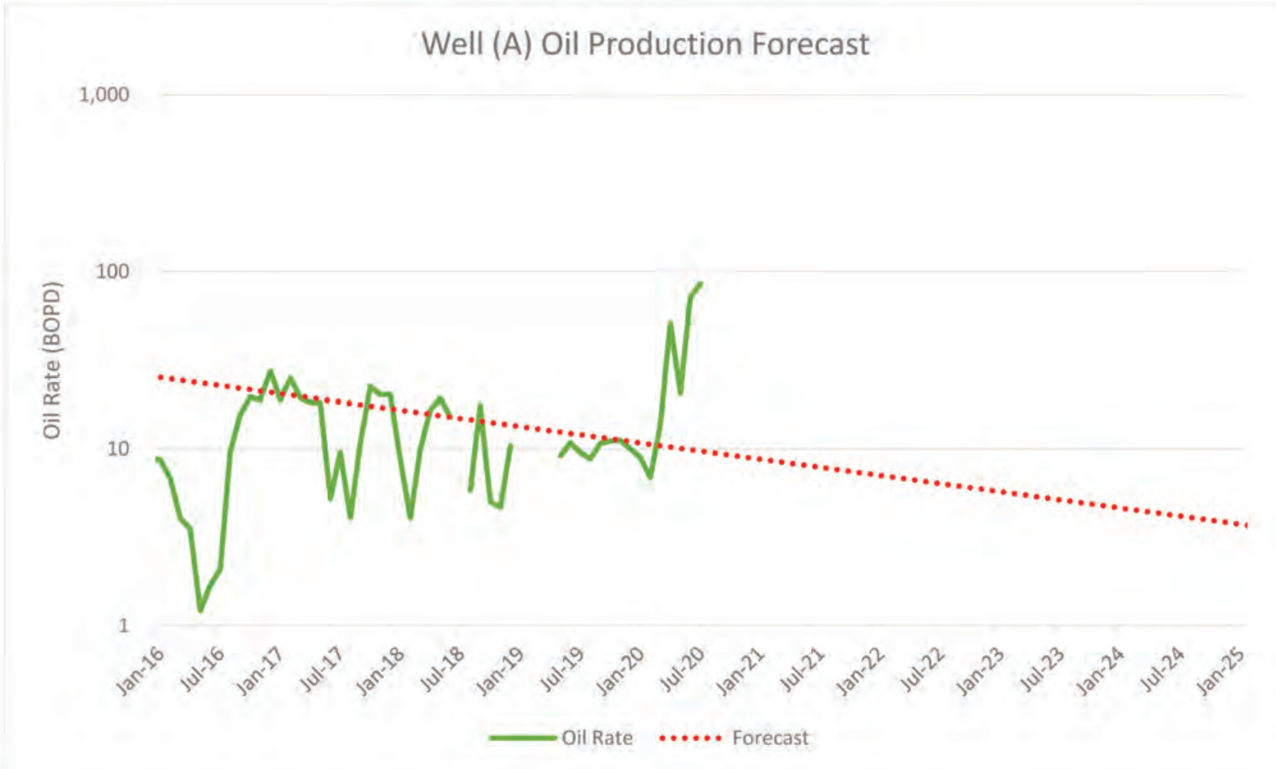

Figure 3—Well (A) short term forecast without an OOR Pilot treatment.

Field Screening & Initial Laboratory Work

Initial OOR technology screening of Tatweer Petroleum's Rubble field was completed in Q2 2019. Reservoir and well technical details were reviewed against OOR's defined technical criteria to determine the suitability of the reservoir for the technology application. Parameters such as oil gravity, reservoir temperature, water salinity, water pH and reservoir permeability were closely considered. A summary of the main parameters aligned to the OOR guidance criteria is detailed below in Table 1.

Table 1—Summary of Rubble screening criteria.

Screening criteria	Rubble Reservoir	OOR technical criteria
Oil Gravity (API)	18	12 – 42
Produced Water pH	7.3	6 - 8
Reservoir Temperature (ºC)	48	<105
Produced Water Salinity (TDS)	60,000	<215,000
Reservoir Permeability (mD)	3.5	> 1

Following positive field screening results a produced water sample was collected from the wellhead of Well (A), and received at the laboratory in Monrovia, California, on August 6th, 2019. For each well to be sampled successfully 2 litres of produced water is required to be collected and sealed in four (4) 500 ml bottles. An example is shown in Figure 4.

COMPANY:	TATWEER PETROLEUM	
FIELD:	RUBBLE	
LOCATION:	BAHRAIN (LAND)	
WELL NUMBER:	A	
DATE:	6/08/19	
TIME:	07:05	
TEMPERATURE AT TIME OF SAMPLE:	40 °C	°F
TEMPERATURE AT TIME OF BOTTLING:	36 °C	°F
pH:		
LAB WORK ORDER NUMBER:	LHUNTIT190223	

Figure 4—Well (A) sample bottles.

Upon arrival at the Titan laboratory two (2) bottles of each well sample were sent to a separate genomics laboratory for DNA and RNA sequencing analysis to identify the microbial ecology present.

Within the laboratory spin and stains were completed on samples from the remaining two (2) bottles to assess whether living microbes were present. After the spin and stain the remaining fluid was taken through a thermal reactivation process by raising the temperature from 20 ˚C measured on arrival gradually over time for 3 to 4 days until the sample reached the minimum reservoir temperature of 42 ˚C. One bottle was carefully agitated in case any microbes had settled out and then individual samples were taken from this fluid to fill a number of tubes. Each of these tubes contained different OOR Process nutrient combinations and concentrations as well as 1 tube containing only sampled produced water as a control.

The top of each tube was flushed with 100 % nitrogen to exclude as much oxygen as possible. These tubes were then incubated at 45 Celsius and in a dry and dark incubator. Every 3 to 4 days the tubes were examined for any growth (usually seen as a gradual increase in turbidity or opacity). A little growth was observed after 3 weeks in the samples at 45 Celsius and a little more after 4 weeks of incubation. At this point samples were taken from the tubes which exhibited this growth, smeared on slides, fixed, and then stained by the Grams differential method with slight variations due to the expected types of microbes. After staining and drying the slides were then examined under a high-power digital imaging microscope for abundance, type and morphology of microbes present and thereafter representative images were taken for documentation and later use for comparison post any Pilot Test (In-Situ Microbial Response Analysis (ISMRA)).

In Table 2, growth results are shown from Well (A) which demonstrate the microbial ecology present, and that it can grow in more than one nutrient combination. These results are needed to support progression of the Pilot test in the field.

Table 2—Growth observations in full work up tubes.

Reservoir Name:	Rubble		
Well Number:	Well (A)		
Incubation Details:	Incubated at 43 - 45°C		
Notes on Entire Set: (Smells, Sediments, Colours)	Tubes had a slight amount of cloudiness at the beginning and very little colour and almost no oil		
Tube	**Contents**	**Tube Observations**	
		06-09-2019	04-10-2019
1	No Nutrients	Very slightly cloudy	Very slightly cloudy
2	1mL control Bacteria	N/A	-
3	1X Nutrients	Slightly cloudy	Slightly cloudy
4	0.1X Nutrients	Very slightly cloudy	Very lightly cloudy
5	2X Nutrients	Slightly cloudy	Moderately cloudy
6	No Alpha	Slightly cloudy	Lightly cloudy
7	No Beta and Alpha	Slightly cloudy	Lightly cloudy
8	No Zeta and Alpha	Slightly cloudy	Lightly cloudy
9	No Zeta	Slightly cloudy	Lightly cloudy
10	No Beta	Slightly cloudy	Lightly cloudy

The designations in Greek letters in the above table stand for various components of the nutrient recipe that are excluded in that test tube.

Staining performed on 13-10-2019

Slide	Slide Observations
1	+
2	N/A
3	+ to ++
4	+
5	++ to +++
6	+
7	+
8	+
9	+
10	+

+ means a few microbes, + to ++ means few to more than a few and ++ to ++ means some to many microbes. Numbers will go from 100 per ml to more than 10,000,000 per ml.

Imaging Studies on samples from Well (A)

In addition to the number of microbes, the type and the morphology were also reviewed. In the partial image in Figure 5 below, an image of the microbes found in the produced water sample is shown that was labelled Tube 1 – Control, no nutrient supplementation.

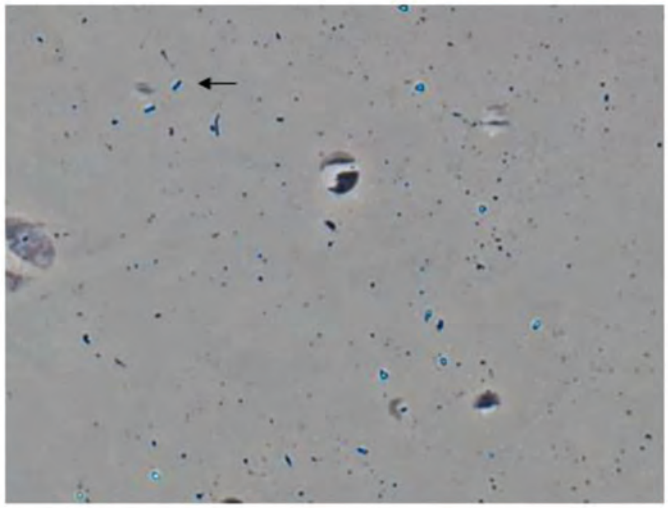

Figure 5—High resolution microscopy image of Tube 1 - Control sample (partial image) shows very few microbes present mostly of rod type and mostly gram positive. The arrow points to examples of the microbes.

Of the other tubes, some growth was observed as shown within the partial image in Figure 6 below.

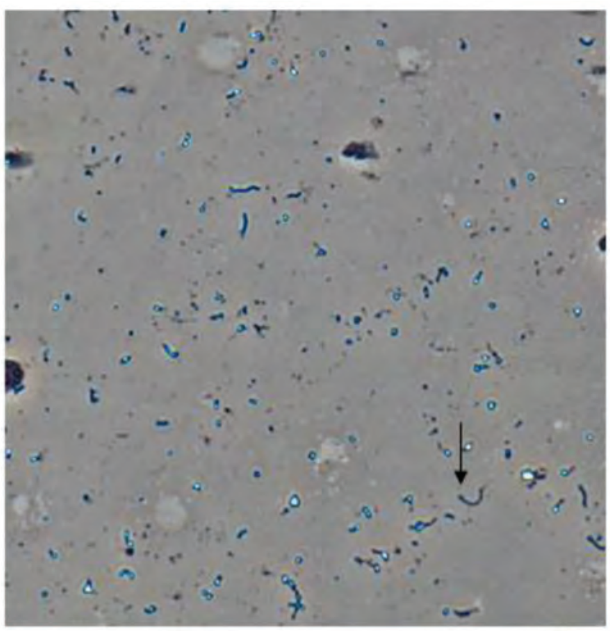

Figure 6—Stained sample from a Tube 5 containing a typical OOR nutrient combination (partial image). There has been an increase in microbe number with some exhibiting morphological changes associated with the activation that denotes a positive result. The arrow indicates rods now in groups known as "chains".

The microbe concentration increased by several times in some tubes and is typical of a positive response. Growth in the laboratory strongly indicates there were living extremophiles present in the samples collected from the well that grew at around 45 ˚C and have been activated and stimulated to grow in the laboratory study.

As well as the growth and microscope imaging studies the diversity of the microbes present in the produced water is examined by a metagenomic study to identify the metabolic traits and microbe families present. We give a simplified example of the results of this analysis for Well (A) sample below.

Genetic Analysis for Well (A) Sample

Archaeal and Bacterial populations of each sample were analysed in parallel by 16s metagenomic sequencing, using MiSeq platform. This approach robustly detects both bacteria and archaea.

The metagenomic analysis showed Rubble Well (A) Produced Water had 9.79E+07 microbes per ml. The Genetic analysis was successful and showed a diverse collection of microbes, many typical of oil field reservoirs.

The Well (A) sample data is shown in Figure 7 below. This shows a significant presence of Thermophilic microbes that can respond to the OOR Process, as well as the presence of Sulfidogens. There is sufficient diversity for the OOR Process to have a significant effect.

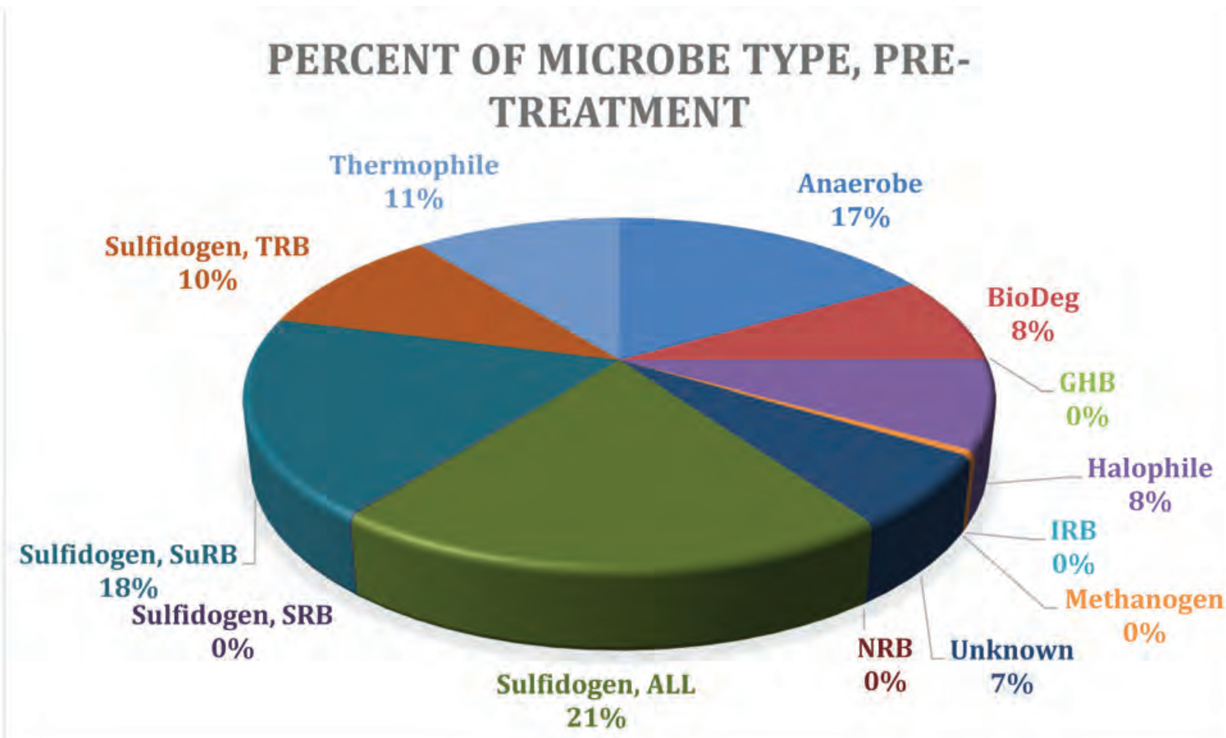

Figure 7—Shows the overall genetic traits present in the analysis of produced water sample from Well (A) performed by metagenomic analysis.

Field Application

Following successful laboratory analysis and microbial evidence which showed that resident microbiology within Well (A), could be activated by OOR nutrient, a Pilot test was initiated within Well (A) in August 2020. The Pilot is typically applied in a single producing well to test a relatively small volume of the nutrient formulation created from the initial laboratory work described in the previous section. In the case of Rubble, there is no waterflooding or water injection program within this field and any subsequent treatments will also progress directly through producing wells.

Rigging Up, Treatment Preparation & Mixing

A closed line hard piping system was constructed next to Well (A) by Schlumberger making use of a pumping truck to allow for the frac tank filled with 'sweet' injection water to be suitably connected to Well

(A). The line was connected directly to the wellhead to allow for the pumping of the treatment into the well via the casing in the form a classic ‘bullheading’ operation. This system ensured that water and nutrient mix could be safely and compliantly introduced to the producing well.

One, 200 litre drum of concentrated nutrient and 100 barrels (15,900 litres) of ‘sweet’ injection quality water was supplied to the well site prior to injection, with the water being stored in a contained 500-barrel (79,500 litres) frac tank.

A pre-injection produced water sample was collected on the 27th July from Well (A)'s wellhead prior to it being shut-in before treatment. The nutrient was then introduced into the frac tank and mixed thoroughly with the 100 barrels (15,900 litres) of injection quality ‘sweet’ water which was already contained in the tank. This was achieved by connecting both the inlet and outlet ports on the tank to the pump truck and thereafter circulating the nutrient/water mixture for 15 minutes to ensure the fluids were thoroughly mixed and homogeneous.

To ensure that there was no contamination from any residual chemicals or other fluids or particulates, prior to any mixing or pumping the tank and all flow lines were flushed with clean fresh water.

Treatment Pumping

On the 1st August 2020 the 101 barrels (16,000 litres) of diluted nutrient was injected directly at the wellhead between the casing and tubing at a rate of 1 bpm for the first 30 minutes and thereafter increased to 2 bpm until the treatment pumping was complete. The injection rates were monitored in real time with the help of specialised software connected digitally to the pumping truck. The total injection time for the treatment was approximately 65 minutes. During the entire duration of pumping the main treatment pressure within the well did not exceed 400 psi. This was below the maximum stated pressure limits of 1200 psi set by Tatweer Petroleum. The maximum pressure is set to ensure safety of the well and prevent any damage to the formation.

First Over Displacement – Post Treatment

To ensure that the nutrients injected are pushed out of the wellbore into the formation, the first of two over displacements of injection quality ‘sweet’ water was applied. This injection consisted of 25 barrels (4,000 litres) pumped at a rate of 2 bpm. This injection equated to 150 % of the tubing volume and took approximately 12 minutes to complete with the maximum pressure within the well not exceeding 1200 psi. After the injection was complete all lines were bled down and removed from the wellhead, and the well was shut-in for a period of 11 days.

Second Over Displacement - Post Treatment

To allow for the increased and activated population of resident microbiology to be pushed further out from the wellbore, a second over displacement of injection quality ‘sweet’ water was initiated on 11th August. The well was rigged up and prepared as described earlier, after which the 50 barrel (8,000 litres) second over displacement was pumped at a rate of 2 bpm for 25 minutes. After the injection was complete all lines were bled down and Well (A) was shut-in for a period of 10 further days. A typical shut-in period for a Pilot test is 10 days total (7 days + 3 days), however due to the heavy nature of the oil and the complexity of the Rubble reservoir it was decided to increase the well shut-in period to 21 days. It was believed that the extra incubation time would increase the stimulated ecology's ability to break down the heavy oil for effective recovery. The extra displacement has proven to result in higher populations of activated microbes being present for a longer period when compared to treatments with a single displacement.

Well Restart

After the 21-day shut-in period was completed the well was brought back onto production on the 22nd August. To help minimise the expected effect to the resident downhole ecology of bringing a well back into full service quickly, flow was gradually increased through production choking. The production choking schedule followed is outlined within Table 3 below.

Table 3—Return well to production choking schedule.

Date	Production Choke
22nd August 2020	25%
23rd August 2020	50%
24th August 2020	100%

Post-Pilot Microbial/Production Response

To understand the microbial response from the Pilot, water samples were taken daily, weekly, and then monthly thereafter. The sampling schedule completed on Well (A) is outlined within Table 4 below, with each ‘sample’ consisting of four (4) × 500ml bottles of produced water from Well (A).

Table 4—Post Pilot produced water sampling schedule.

Date	Sample # & Day from Injection
27th July 2020	Sample #1 – Pre-treatment sample
22nd Aug	Sample #2 – 90 mins after restart
22nd Aug	Sample #3 – 3 hours after restart
23rd Aug	Sample #4 – 25 hours after restart
24th Aug	Sample #5
25th Aug	Sample #6
/	n/a
/	n/a
3rd Sep	Sample #8
10th Sep	Sample #9
17th Sep	Sample #10
21st Oct	Sample #11
24th Nov	Sample #12

Each sample was analysed in the Titan laboratory where the microbe content was assessed both for abundance and evidence of activation using a staining and imaging technique and a limited growth analysis to ensure the microbes were living. Figure 8 shows an example of an image from Sample #2 (90 minutes after well restart).

The laboratory image outlined in Figure 8 indicates that there were numerous microbes present, numbering approximately 37.125 million per ml within Sample #2, while Figure 9 shows approximately 31.875 million microbes per ml present for Sample #5. When comparing these post treatment microbial populations against the pre-treatment sample population of 9.125 million microbes per ml it can clearly be see that there has been a significant increase in the microbial population resulting from the treatment process.

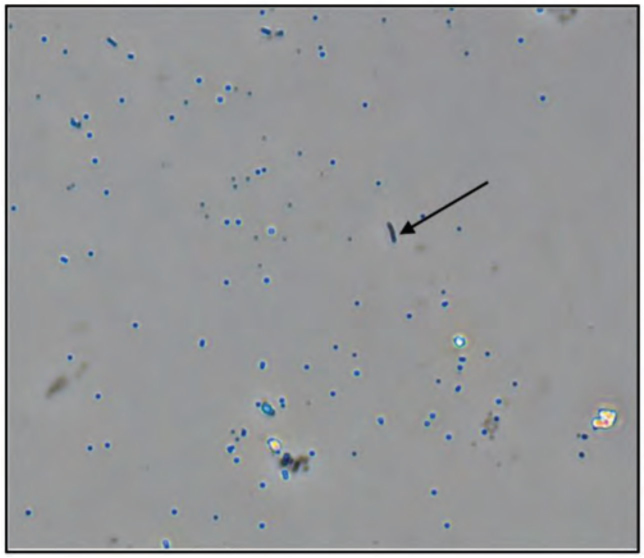

Figure 8—Image from Sample #2 staining showing activated microbes. The arrow points to a short chain of rod-shaped microbes. There are numerous microbes of both cocci and rod varieties present.

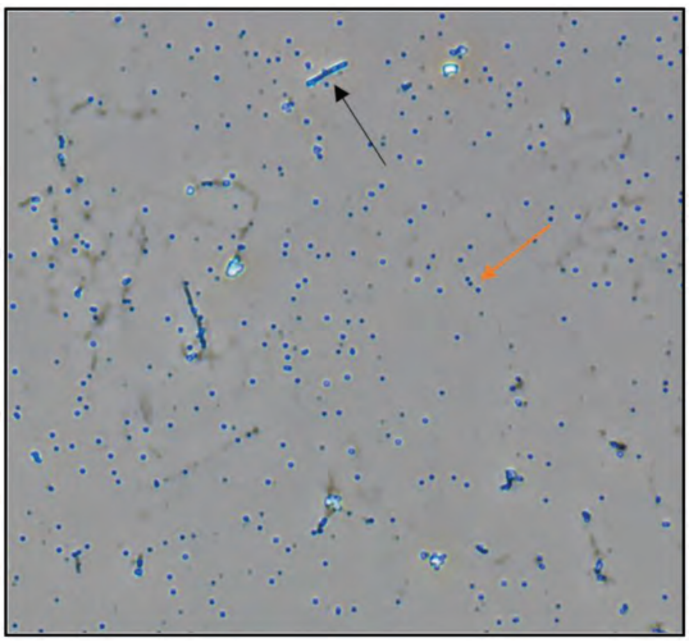

Figure 9—Image from Sample #4, 2 days after well re-start, showing an increased number of microbes present and changes in morphology. Microbes in chains (black arrow for example of rods and orange arrow for cocci) indicate activation of the microbes by the Titan nutrient mixes.

In Table 5 on the following page, an estimate of the microbes per ml in each sample is given to provide an overview of how the OOR Process has worked over time, post-Pilot injection. The microbial populations from each post-Pilot sample were calculated by using the microns per pixel of the laboratory microscope images extrapolated from the known volume of liquid placed on the slide, aligned to the area over which the fluid is spread. The resulting number is accurate as regards the slide but may vary by up to a magnitude in the actual sample due to the small volume taken. The sample itself taken from the well is also small in comparison to the total water produced from the well each day. Nevertheless, if microbes in the millions are found post OOR treatment, it is a strong indication that the OOR Process has taken effect.

Table 5—Post-Pilot produced water microbial populations (from slide counts).

Sample #	Notes / Observations for Well (A)			
Sample #1 Pre-treatment	Notes: None			
	Microbe Count in Field	146	**Microbe Count/ ml**	9,125,000
Sample #2	Average Microbe Count in field: 310 Average Microbe Count / ml: 19,374,833			
	Microbe Count in Field – Figure 10	594	**Microbe Count/ ml**	37,125,000
Sample #3	Notes: None			
	Microbe Count in Field	575	**Microbe Count/ ml**	35,625,000
Sample #4	Notes: None			
	Microbe Count in Field	615	**Microbe Count/ ml**	38,437,500
Sample #5	Notes: None			
	Microbe Count in Field	510	**Microbe Count/ ml**	31,875,000
Sample #6	Notes: Did not receive sample due to lack of water – oil cut almost 100%			
	Microbe Count in Field	/	**Microbe Count/ ml**	/
Sample #7	Notes: Did not receive sample due to lack of water – oil cut almost 100%			
	Microbe Count in Field	/	**Microbe Count/ ml**	/
Sample #8	Notes: None			
	Microbe Count in Field	348	**Microbe Count/ ml**	21,750,000
Sample #9	Notes: Average Microbe Count in field: 62.3 Average Microbe Count / ml: 3,895,833.33			
	Microbe Count in Field – Image#1	55	**Microbe Count/ ml**	3,437,500
	Microbe Count in Field – Image#2	75	**Microbe Count/ ml**	4,687,500
	Microbe Count in Field – Image#3	57	**Microbe Count/ ml**	3,562,500

The pre-treatment sample taken had approximately 9.125 million microbes per ml. This population was similar to the numbers measured within the original produced water samples taken in August 2019 to determine if this well was suitable for the OOR Process. This can therefore be considered a reliable baseline for Well (A).

All the samples taken after the Pilot test treatment and shut-in period, except for sample #8 had more microbes per ml than the pre-treatment sample. The presence of microbes increased with time for the first few samples and then began to drop off for a few days followed by a further increase in microbes towards the end of the sample period being reviewed. This is very typical of the OOR response. The nature of the sampling process provides a moment in time of the reservoir ecology and thus should be seen as indicative of real time changes.

In addition to the population increase there was also a clear increase in microbes which indicated a response to the OOR Process, where the nature or the microbe changes from being Hydrophilic to being Hydrophobic through nutrient limitation. The maximum number of microbes seen in this series was more than 20-fold higher than the pre-treatment sample. The post treatment samples had a majority of microbes that had morphological changes consistent with the activation to the Hydrophobic form.

When post treatment samples are received, as well as staining and imaging, some of the samples are put back in nutrients to determine what percent are still alive and capable of growth, and if they are still activated by the OOR Process. If available, a genomic analysis is also performed (this was not available for these samples due to Covid-19 causing shortages of ingredients used in the analysis). Tubes were set up for growth from Samples #3, #8 and #9 using no nutrient addition and two concentrations of the nutrient mix used in the well treatments and incubated at the Bottom Hole Temperature (BHT). After one week the control had very little sign of growth and both concentrations had very clear growth. This confirms that living microbes were present in the samples taken at the well head and that they grow at the nominal BHT.

Samples were taken from these tubes and stained and imaged to demonstrate the growth and diversity of the microbes present in the well sample. In Figure 10 below, we show an example of the stained and imaged microbes from one nutrient concentration.

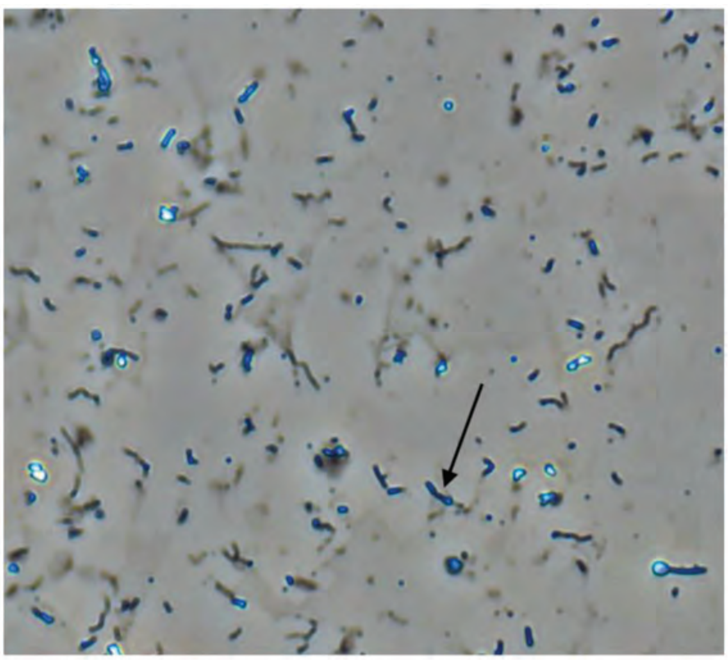

Figure 10—Image of stained microbes from Tube 3, a low concentration of the nutrient recipe. The arrow points to chain of rods. There are many short chains and many rods and some cocci.

Following Well (A)'s production re-start on the 22nd August, a program of well testing was completed. Well tests on Tatweer Petroleum's Awali field are undertaken by third party service companies and are completed through connecting each individual well to a mobile test separator. Fifteen (15) individual well tests of the same duration of 6 hours were completed at planned intervals and the results are shown in Table 6 below. The first well test took place on the 23rd August 2020, one day after the well was re-started.

Table 6—Well (A) - Well Tests pre and post treatment.

Test date	Duration	Water Cut	Oil	Water	Liquid. Rate
	(Hr)	(%)	(bpd)	(bpd)	(bpd)
2/2/2018	6 hour	94.95	5	94	99
11/3/2018	6 hour	56.1	18	23	41
16/5/2018	6 hour	30.55	25	11	36
3/9/2018	6 hour	81.13	20	86	106
3/10/2018	6 hour	80.77	5	21	26
24/11/2018	6 hour	82.22	8	37	45
1/12/2018	6 hour	82.22	8	37	45
4/12/2018	6 hour	83.33	11	55	66
8/12/2018	6 hour	84.52	13	71	84
20/6/2019	6 hour	75.47	13	40	53
17/01/2020	6 hour	62.85	13	22	35
27/03/2020	6 hour	40.59	60	41	101
23/05/2020	6 hour	99.19	1	123	124
12/06/2020	6 hour	15.85	138	26	164
20/07/2020	6 hour	30.95	58	26	84
1/08/2020	*Pilot Nutrient Injection*				
22/08/2020	*Well re-start*				
23/08/2020	6 hour	99.47	0.74	138.75	139.49
04/09/2020	6 hour	13.2	152.11	23.12	175.23
07/09/2020	6 hour	38.58	99.48	62.48	161.96
10/09/2020	6 hour	40.35	114.9	77.72	192.62
13/09/2020	6 hour	45.64	102.95	86.42	189.37
16/09/2020	6 hour	36.01	127.35	71.66	199.01
21/09/2020	6 hour	8.06	223.93	19.63	243.56
24/09/2020	6 hour	38.17	160.09	98.84	258.93
25/09/2020	6 hour	50.04	114.81	115	229.81
13/10/2020	6 hour	63.01	87.76	149.48	237.24
19/10/2020	6 hour	55.72	105.88	133.24	239.12
25/10/2020	6 hour	38.84	168.02	106.72	274.74
29/10/2020	6 hour	35.83	200.21	111.79	312
13/11/2020	6 hour	76.32	56.67	182.66	239.33
19/11/2020	6 hour	91.64	9.84	107.84	117.68
25/11/2020	6 hour	99.32	1.6	232.94	234.54
01/12/2020	6 hour	42.83	134.08	100.46	234.54
07/12/2020	6 hour	50.4	121.68	123.66	245.34
13/12/2020	6 hour	65.61	152	290	442
14/12/2020	6 hour	65.60	130	248	378
19/12/2020	6 hour	64.74	140	257	397
27/12/2020	6 hour	64.92	147	272	419
26/01/2021	6 hour	65.44	122	231	353

The first well test completed on the 4th September measured on average an oil production rate of 152.11 BOPD with a total liquid rate of 175.23 BPD. This oil rate was the highest tested rate since 2009 and similarly the well's water cut from the first well test was measured at 13.2 %, which again was one of the lowest tested within a period of over 10 years.

Analysing the post treatment well test numbers against the pre-treatment forecast, as seen in Figure 11 on the following page, it can be interpreted as showing a response in the production due to the OOR Pilot injection. This response continued for more than 3 months from well re-start. Similarly, the well test water cut of the fluid showed significant change following OOR treatment. When these numbers are considered against the laboratory results, particularly the microbial population outlined within Table 5, they point to a correlation between the production and microbial response.

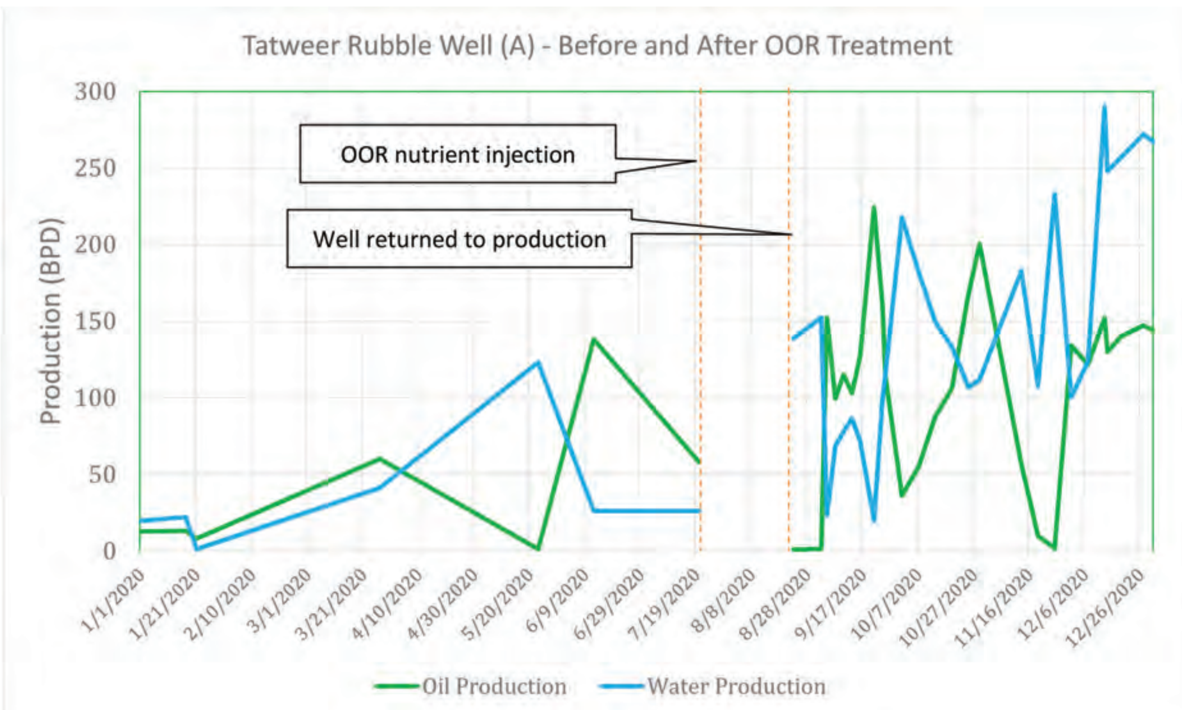

Figure 11—Comparison of OOR Pilot treatment production results against the pre-treatment forecast for Well (A).

The increase and peak microbial populations coincided with the increasing numbers of activated microbes seen in the samples over the first two weeks. Given that the oil production is still above baseline beyond the last scheduled well test, monitoring of both the production and microbial response has continued.

A continuous steam injection program has been ongoing in the vicinity of Well (A) since Q3 2020. The steam injection well is located approximately 800m away from producer Well (A). The microbial analysis of the post-Pilot produced water does not support the theory of a direct steam injection impact on Well (A) production, as the microbes sampled and analysed were still growing at the original BHT. Additionally, there is no indication that analysed reservoir microbes were being killed off by higher temperature steam condensate from the steam injection program. It is worth noting that the well temperature seems to be around 45C which is fairly cool and not indicative of heat, at least, reaching this reservoir area from the nearby steam injection.

Nevertheless, the significant increase in the total liquid production post treatment (Table 6) can only be explained by the change in reservoir dynamics, whereby the steam injection, which is likely to have turned to hot water quickly upon injection, introduced a pressure support mechanism. Moreover, the water salinity analysis post treatment on the producer showed lower figures compared to the average water salinity across the Rubble formation, which suggests a fresh water source has been introduced as result of the ongoing steam injection.

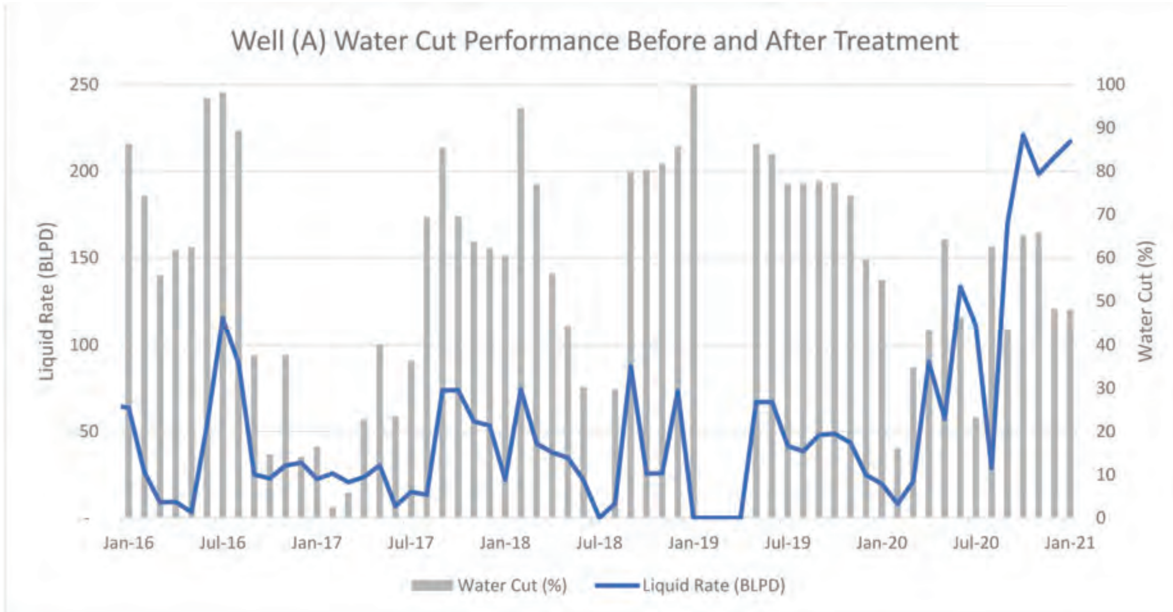

Figure 12—Well (A) well test water cut comparison.

In summary, the combined effect of the organic oil recovery treatment with the introduction of a pressure support mechanism in such a tight, highly fractured, and low-pressure reservoir is likely to have been a major factor to the success of the Pilot.

Conclusions/Discussion

During the initial laboratory testing of Well (A) the reservoir showed a diverse and abundant resident ecology which was deemed capable of undertaking the necessary characteristic changes to facilitate enhanced oil production. With the presence of energy in the reservoir, through the application of a pressure support program, the Pilot test results have proven both a strong microbial and production response, which demonstrates that Organic Oil Recovery technology has been successfully applied to a heavy oil producing carbonate field in Bahrain. A strong correlation between the microbial and production responses has been implied through the mapping of microbial population growth and microbial nutrient limitation against the measured production response.

With the presence of the energy in the reservoir, whether it is natural (i.e. active water aquifer) or provided through an artificial pressure support program (i.e. waterflood or steam flood), OOR has proven to release additional trapped oil with a relatively small contact area in heavy oil. This opens new opportunities to take advantage of existing heavy oil fields to recover trapped oil which would not normally be produced and left in ground at the end of the field's life. In fields where steam flooding or water flooding can be applied the use of OOR technology could be considered to further enhance oil production in heavy oil reservoirs.

Acknowledgements

We thank Schlumberger for their effective onshore well intervention operations and Haimo for their well testing work on the Rubble reservoir, during the Pilot.

Finally, we would like to thank Tatweer Petroleum, for their full support during all phases of the sampling and Pilot testing of Organic Oil Recovery Technology.

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Field Studies of Microbial EOR

A.J. Sheehy, U. of Canberra

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ABSTRACT

Microbiologically enhanced oil recovery (MEOR) is the use of microorganisms to facilitate, increase or extend oil production from a natural reservoir. The concept is more than 40 years old, however, early proposals were poorly conceived and in most instances of no practical value. Recent studies have developed microbial biotechnology to resolve specific production problems such as pressure depletion and sweep inefficiency in a target reservoir.

Field trials to determine and document the effectiveness of microbial process, and to assess the validity of laboratory studies and models have been conducted. The application of MEOR in these trials has resulted in a substantial and sustained increase in production compared to control operations on the same reservoir. Increased production has been sustained from a single treatment.

A field assessment of the new technology in the Alton field is described. Twelve months after treatment an approximate 40% increase in net oil production continues. The test is unique because of the stringent controls applied during the assessment.

INTRODUCTION

Alton Field

The Alton Field is located 370 km (230 miles) west-southwest of Brisbane in the Surat Basin, Queensland, Australia. The Alton Field produces from Lower Jurassic, Boxvale Sandstone which is part of the Evergreen formation. The trap is structural-stratigraphic; small anticlinal closure with reservoir zones controlled by permeability barriers and edge-water contacts. The reservoir temperature is 76°C (169°F). Production commenced in January 1966 and at present the field is producing on beam pump from five wells.

References and illustrations at end of paper.

The individual sands in Alton tend to be thin with a permeability of 11 to 884 md (average 260 md) and porosity of 15.4 to 19.8% (average 17.2%). The permeability and porosity decrease from east to west. The hydrocarbon areal extent is 1840 acres. The original oil in place has been estimated at between 6.6 million STB and 13.6 million STB. Oil produced is medium light on a paraffin base. Residual oil concentration is about 50%. The pressure and production history indicates the presence of a weak water drive which is supplemented by fluid expansion.

The Alton Reservoir commenced production at a rate of 1000 STB/day. Field production started a slow decline in 1969 and there has been a roughly exponential deline since. In recent years that decline has been measured at approximately 15 percent per annum and the reservoir is close to its economic limit of 15 STB/day.

The low primary recovery and high residual oil saturation make Alton a prime candidate for enhanced oil recovery. After initial evaluation it was considered that a waterflood would be too expensive and the stratified nature of the sands at Alton were considered to militate against its likely success.

A decision to stimulate the well biologically was made on the basis that microbial biotechnology was likely to achieve increased production via the simultaneous application of (i) profile improvement of aquifer sweeping (ii) increased pressurization and (iii) surfactant, at a cost consistent with the economic potential of the reservoir. The stimulation was conducted by injection into the producing well.

Microbial EOR

Microbial EOR is the application of biological processes to facilitate, increase or extend production from an oil reservoir (Jack, 1988). The basic thrust for microbial EOR is the same as for other biotechnologies i.e. the extreme diversity of microbial metabolites that can be produced by microorganisms and the relatively cheap feedstocks that can be used in their production. A further potential benefit is that bacteria which produce useful metabolites can be grown within the reservoir, thus avoiding losses due to adsorption to rock surfaces and the physical and chemical conditions of the reservoir.

The concept of using microorganisms to enhance oil recovery was proposed more than 40 years ago and resulted in a field test in 1954 (Yarborough and Coty, 1983). However, the early proposals in this field were poorly conceived and in most instances of no practical value, e.g. many proposals included the use of sulphate-reducing bacteria as the inoculum. As a consequence the petroleum industry developed extreme scepticism towards MEOR. The scepticism was amplified by subsequent literature which consisted of anecdotal accounts of transient increases in oil recovery and unsubstantiated claims based on inadequately or uncontrolled studies.

In recent years, a number of national and international conferences, symposia and workshops have reviewed Microbial EOR (Burchfield and Bryant, 1988; King and Stevens, 1987; Zajic and Donaldson, 1985). Presentations at these meetings can be grouped into two broad areas. The production by microorganisms of metabolites which mimic traditional chemical and miscible EOR strategies and processes for the injection, dispersion and nutrition of microorganisms in petroleum reservoirs. These meetings have resulted in the generally accepted principle that Microbial EOR is not a single technology based on a common approach; rather, it is the adaption of microbial systems to specific problems of oil recovery from a chosen target reservoir (Jack, 1988).

LABORATORY STUDIES

In the laboratory, microbial species which produce biometabolites capable of augmenting petroleum recovery were isolated and enriched. Factors which optimise the production of these biometabolites were determined and studies of the effects of environmental stresses such as temperature and ionic strength conducted. Screening of isolates was conducted in sandpacks. Final selection and optimisation of growth parameters and biometabolite production was conducted in an apparatus designed to reproduce the physical parameters encountered in the target reservoir. This apparatus is capable of providing simultaneous studies of oil release from sand or core specimens.

Investigations on the interactions between biometabolite producing species and the resident microbiota of the reservoir also were conducted. Finally, a series of core flood experiments on the optimised system were conducted using produced fluids from the well and under the physical and chemical conditions determined to be present in the reservoir.

FIELD STUDIES

The aims of the field trial were to determine and document the effectiveness of the new biological process, and to assess the validity of laboratory studies and models. A series of controls was included in the field trial to make the assessment of the process scientifically valid (Graph 1). The controls included:

(A) a trial shut-in period to log post shut-in production and document the natural baseline,

(B) injection of production water, followed by well shut-in, to log hydrodynamic changes in the well caused by the workover programme and document an injection baseline.

All evaluations of the effectiveness of the Microbial EOR system are determined against these controls.

Workover programme

A standard workover programme was conducted on Alton #3 to set a packer to ensure that the microbial mixture entered the formation. Plug Back Total Depth was 6109 ft RKB.

Fluid injection of 0.5 bbl/min. at 2200 PSIG was maintained during pumping. A total of 86 bbls of microbial solution was injected. All fluid injected into the formation was filtered through 28 and 10 micron filters. 35 bbls of produced water was used to displace the microbial solution. The total cost of the microbial injection was $A3850. The workover programme was completed on Thursday 26 January (Australia Day) and the well put back on production Thursday 16 February 1989.

RESULTS

Graphs 1 to 4 show the changes which result from the introduction of the Microbial EOR system. Graph #1 shows the production history in barrels of fluid produced per day (BFPD) and barrels of oil produced per day (BOPD) of Alton #3 during the period January 1986 to January 1990. Point A indicates the point at which the well was shut-in. Point B indicates the injection of production water and Point C the introduction of the Microbial EOR system. The increase in oil production after the application of the Microbial EOR system is clearly evident from February 1989.

Graph #2 shows oil production on a daily basis for the microbial system (Test) referenced against the injection baseline (Control). There is an approximate 40% increase in production. It should be noted that the oil flow recommenced after the introduction of the microbial system at a relatively constant rate where the flow of the control was quite erratic. Oil production figures combined with geochemical data (not presented) clearly shows that oil previously trapped has been released from the formation.

Graph #3 shows how the level of base sediment and water (BS&W) or water cut) was reduced after the microbial process was applied to the well. Clearly, the water cut has decreased and the percentage of oil contained in the total fluid produced has risen.

Graph #4 shows the increase in oil production resulting from the microbial system by plotting cumulative oil production (Cum. oil prod'n) against cumulative stream days.

Other significant findings were:

(i) An increase in annulus pressure shown both chemically and by gas analysis to be predominantly the result of biological activity. The major components in the increased gas pressure have been contributed by carbon dioxide and methane production.

(ii) Chemical analysis of the production water before the programme began, after nutrient medium injection and after the introduction of the microbial system shows that the production water after the microbial injection contains levels of Na^+, HCO_3- and Cl^- greater than those in the initial production water and support medium. Peak levels of these ions were associated with maximum oil production. This is consistent with the release of connate water and associated oil as a result of an improved sweep efficiency.

(iii) Microbial numbers increased from less than 1000/ml in the pre-injection production water to greater than 100,000/ml after the microbial injection. Sulphate reducing bacteria were not stimulated and H_2S was not detected.

(iv) No changes occurred in the composition or physical characteristics of the oil.

(v) The interfacial tension of the production water/oil interface was significantly decreased (10-25%) compared with that prevailing before the microbial injection.

(vi) The field trial results and laboratory core flood experiments have similar production patterns.

Cost

In the evaluation of costs associated with the test at Alton it must be appreciated that this trial was designed primarily to provide scientific data. It should be noted that the volumes injected and therefore potential yields were restricted at the request of the well owners. An estimate of the cost of the injection cannot be taken in isolation so the following calculations are based on on-going use of Microbial EOR in further wells in the same reservoir.

Cost of chemicals injected:	$A3850
Value of chemicals recovered (90%):	$A3465
Net Cost of injection:	$A 385

From these calculations it can be deduced that the application would cost less that $A1 per incremental barrel as a waterflood adjunct. Further evaluation of total costs should be undertaken in a field trial designed for economic potential.

DISCUSSION

Until this test, field trials using microbial systems and processes have not been conclusive. This has been due to the complex nature of oil reservoirs, limited access of organisms to oil bearing areas of the formation and poor survival of surfactant and gas producing microbial systems in the high temperatures, pressures and ionic strength that prevail in many reservoirs. In addition, a lack of scientifically designed controls frequently has lead to disputes on the role of these systems in any improvement of oil production.

This field trial has shown not only the feasibility of stimulating oil production biologically but the capability of this process to operate at temperatures above those traditionally associated with biological processes. It is clear from the field trial that a biological system can be introduced and dispersed over a significant portion of a reservoir even when only a small volume is introduced into a producing well. The system subsequently can be induced to produce biometabolites which dramatically increase oil production.

The process used in this field trial is based on an ecological solution to the problems which have plagued oil production. The process relies on inducing desirable metabolic activity in a biological system rather than attempting to inject microorganisms which already produce desirable metabolites. Thus, the patented process has the unique property of flexibility e.g. it has been shown to be equally effective at 40°C and 76°C and over a variety of ionic strengths and brine and oil compositions. It has the added advantage that the stimulation can achieve increased production over a period of time.

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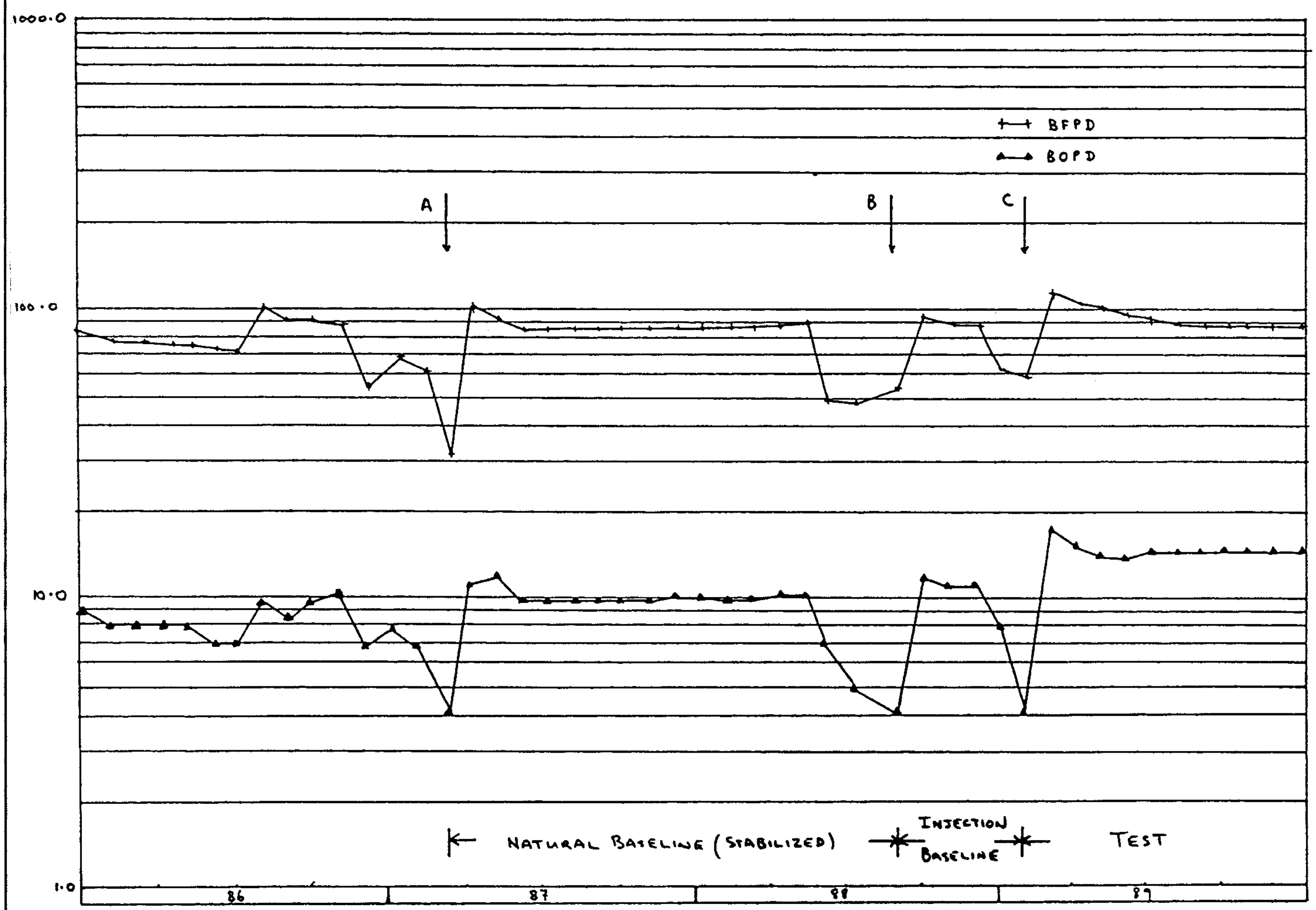
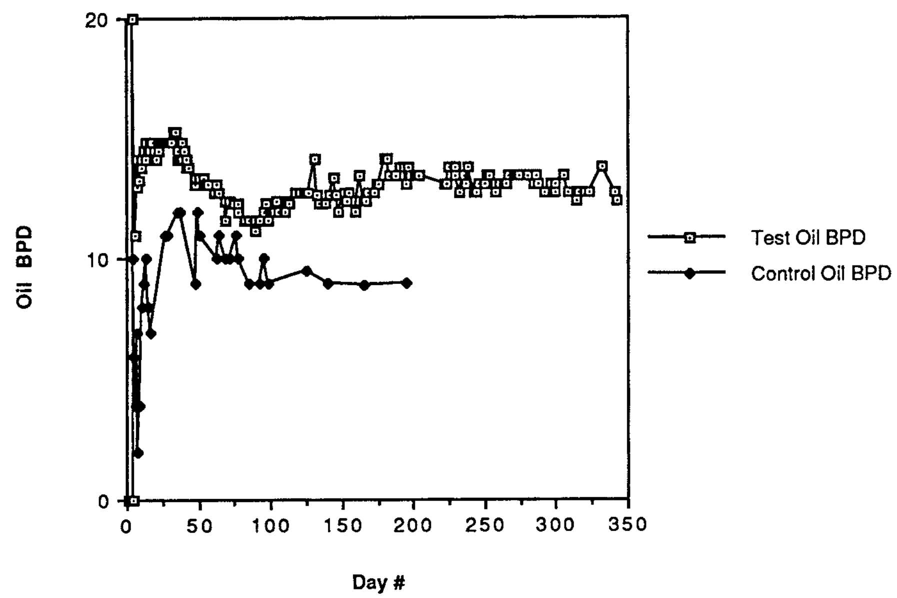


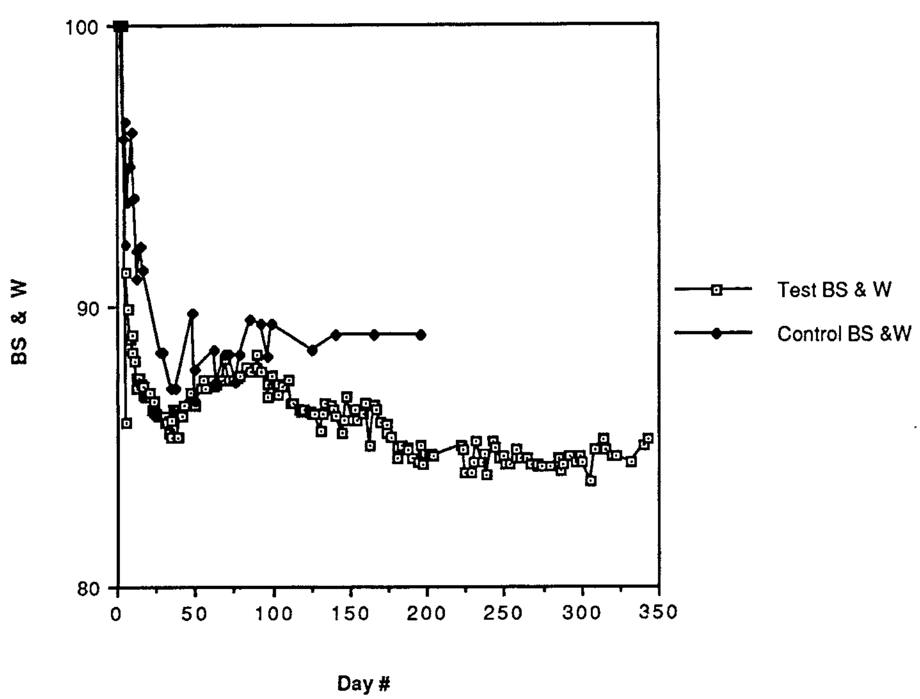
Graph 1—Production history of Alton No. 3—1986 to 1990.

Oil production

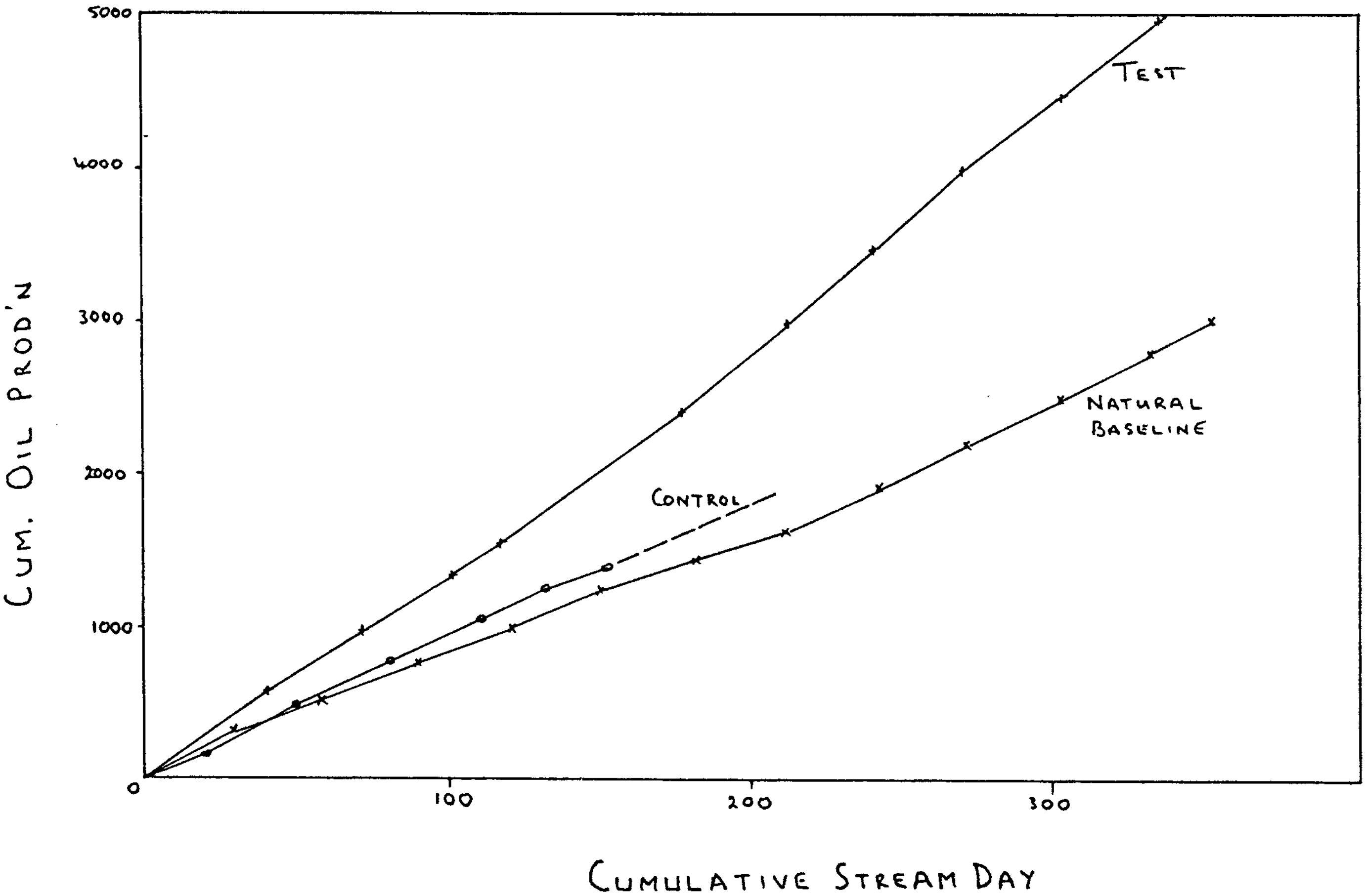


Graph 2—Microbial EOR—daily production.

BS & W



Graph 3—Microbial EOR—water cut.



Graph 4—Microbial EOR—cumulative oil production.

SPE 154216

A Texas MEOR Application Shows Outstanding Production Improvement Due To Oil Release Effects On Relative Permeability

Folami Akintunji, SPE, Atinum E&P, Inc.; Brian Marcotte, SPE, Alan Sheehy and Bradley Govreau, SPE, Titan Oil Recovery, Inc.

This paper was prepared for presentation at the Eighteenth SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, USA, 14–18 April 2012.

Abstract

A Microbial Enhanced Oil Recovery (MEOR) application in the Big Wells Field located in Dimmit County, Texas has shown a significant improvement in production—both oil rate and water cut performance. As a result of a specific nutrient injection designed in the laboratory to stimulate in situ, naturally occurring microbes, for this San Miguel sandstone reservoir and its microbial ecology, a marked improvement was seen in the two producing wells to which the treatment was applied. The water cut in one well improved from fifty per cent to fifteen percent. The water cut in a second well improved from fifty-five to thirty-five percent.

Although previous field applications of this MEOR process had shown increases in oil production and decreases in water production, water production in this application was completely stopped for a brief time as a result of the treatment. This paper reviews the Big Wells producing well treatments and their results. A specific look at the oil release mechanism of this MEOR process offers an explanation as to how the oil released by these treatments impacts the relative permeability of fluids in the reservoir near the treated wellbores as demonstrated in the field producing well treatments. Similar benefits are seen during the treatment of water injection wells related to performance in adjacent producing wells.

The significance of this application is that field evidence supports that production improvements result from the release of oil in sufficient quantities to change the near wellbore relative permeability to both oil and water. Also, it demonstrates that this MEOR technology can be successfully applied to reservoirs in this geographical area and extends the lower threshold for formation permeability suitable for treatment. Having been successfully applied in other parts of North America, this is an important application of this MEOR technology in Texas.

Introduction

Between July 2007 and the end of 2011, there have been 183 applications of MEOR to enhance recovery of North American waterfloods in a programmatic approach of organic oil recovery. Organic oil recovery results from the management of the indigenous microbial ecology to facilitate the release of oil in the reservoir. The application of this process typically consists of five steps: 1) initial field screening, 2) well sampling and laboratory analysis, 3) application of the nutrient formula developed in the laboratory to a single producing well to assure the microbial response under actual field conditions replicates lab results, 4) pilot testing (if applicable) in a representative portion of the waterflood and 5) full-field application. Forty-four treatments have been applied to forty-one producing wells and one hundred and twenty-three treatments have been applied to forty-one injection wells. From the results available to date, on average the wells and their adjacent producers have seen an oil production increase eighty-eight per cent of the time. On average, these applications have resulted in a 102% increase from pre-treatment rates to post-treatment maximum rates. Table 1 shows the results available as of January

1, 2012. The two treated producers were in the Big Wells field and were considered as step #3 in the above five-step approach to field treatment.

Table 1. Over one hundred and eighty applications were performed in 98 wells through 2011.

Summary	Number of Wells	Number of Treatments	Number of Increases	Success Rate	% Oil Increase
PRODUCERS	41	44	32	78%	186%
Pending	1	1			
INJECTORS	41	123	40	98%	35%
Pending	15	15			
ALL WELLS					
Wells Treated-Confirmed Results	82	167	72	88%	102%
Wells Treated - Pending	16	16			
TOTAL	98	183			
* Pending: waiting results.					

Field Background

The Big Wells Field is located in south Texas about 149 miles (240 km) southwest of San Antonio. The field was discovered in 1969 and waterflood operations were initiated in 1971 on an inverted five spot pattern. In 1974 infill drilling was started because of very poor waterflood response on 80 acre (32.4 ha) well spacing.

The main producing zone of the Big Wells Field is the San Miguel/Olmos formation. This formation is a very silty and shaley (calcareous) sandstone with very fine grain sand and mica. This reservoir is 5,500 feet (1,676 meters) deep. Gross pay is estimated to average 200' with net pay of 50'. The porosity is 20% and the permeability 40 md. Bottom hole temperature is 178^{o}F (81^{o}C). The oil gravity is 33^{o}API and the oil viscosity is 2.5 cp at reservoir temperature.

Produced water has total dissolved solids (TDS) of 34,000 ppm with sodium, calcium and magnesium the dominant cations. The dominant anion is chloride at 23,400 ppm. The water composition would tend towards a positive scaling potential. From a microbial perspective, the San Miguel formation is moderate to high in temperature and low to moderate in TDS.

Current production is 90 BOPD, 96 BWPD and 26 MCFPD from the Atinum properties. Prior to treatment, oil production was noted to create an emulsion, which occurs during production and is somewhat difficult to break. On the Atinum leases there are 14 producing wells, 68 idle wells and 1 water disposal well. The waterflood has been inactive for twenty years, although the operator is considering the reactivation of the waterflood. Cumulative production is 5 million BO, 1.4 million BW and 4 BCF of gas from the Atinum properties. In 1986 cumulative production from the entire field was reported to be 6 million BO. With 31.5 million barrels OOIP, 19% of the OOIP had been recovered from the Big Wells Field when well spacing was on 80 acres. (Reviere, R. H. 1986).

Oil Release Mechanism

Unlike many previous attempts at MEOR, this organic oil recovery process does not attempt to introduce microbes into the oil-producing reservoir (Sheehy, A. 1990). Instead, indigenous microbes are stimulated to grow and reproduce due to the introduction of a reservoir-specific mixture of environmentally benign nutrients. The approach needs to be customized to accommodate the different microbial ecologies in each reservoir. In the ideal application, the water injection system becomes the transport medium for the nutrients, distributing the nutrients throughout the reservoir. By activating certain species of microbes, changes in the flow characteristics of the oil are affected and induce the reservoir system to release additional oil to the active flow channels (Town, K. 2010). Stimulated microbes act at the interface of reservoir oil and water altering the flow potential in the producing formation. In the higher permeability portions of the reservoir, newly released oil, water and microbes may interact to form a transient (temporary) micro-emulsion that may alter the sweep efficiency of the injected water as it moves through the reservoir but this is not seen in all cases based on surface indicators. Based on laboratory data, it is believed that in a waterflood, this process can recover up to an additional 10% of the original-oil-in-place. (Davis C. P. 2009)

Reservoir Screening and Lab Work

The application of this organic oil process typically consists of five steps: 1) Initial field screening, 2) Well sampling and laboratory analysis, 3) Apply the nutrient formula developed in the lab to a producing well to determine the microbial response is maximized, 4) Pilot testing (if applicable) and 5) Full-field application. Because the waterflood has been inactive for a number of years, the normal five steps could not be followed. For Step 3, Atinum planned to treat two producers after the completion of the lab work to check the field response to the laboratory-developed nutrient mixture.

Although most of the parameters of the Big Wells Field were well within the range of past successful application, some specific characteristics of the Big Wells Field placed the field at the margins for successful treatment. There were two primary concerns. One concern was the ability of an organic oil recovery process to work in reservoirs of permeability of less than 50 md, previously believed to be the lower limit of MEOR applications. A second concern was the low energy level of the reservoir. Even if the process worked, would the reservoir have enough energy to move the released oil to the producing wellbore? Reservoir temperature was also on the high-end of normal treatment parameters.

In January 2010, produced fluid samples from both wells A-8 and B-17 were taken and shipped to the laboratory for detailed analysis. Based on the lab work, it was determined that the targeted microbes were present and that they responded well to nutrient stimulation. See Table 2 for an example of the increase in number of microbes and the number of oil interactive forms.

Table 2. Targeted Microbes Respond Well to Nutrients.

Well	Number of microbes*	Microbial biodiversity*	Oil-interative microbes*
B-17 January 21, 2010 Low nutrient levels	Greatly Increased	Increased	Greatly Increased
B-17 January 21, 2010 High nutrient levels	Greatly Increased	Increased	Greatly Increased

*Comparison to untreated produced fluids

Producer Treatment Summary

Preliminary screening of the field and microbial assessment of produced fluid samples led to the injection of nutrients into Big Wells A-8 and B-17 on November 3, 2010. Produced water was stored in temporary tanks near the wellheads prior to treating the wells. A chemical tote of specially blended nutrients developed from the lab work was delivered to each of the wells to be treated. The nutrients in each tote were blended with 100 barrels of produced water and displaced with produced water into the producing formation. The treatments were injected down the casing-tubing annulus and no rig was required to pull either the rods or the tubing. The nutrient treatments were injected at very low pressure and there was no difficulty in pumping the treatments in spite of the reservoir's low permeability. See Table 3 for injection rates and pressures.

Table 3. Treatment and Displacement Parameters

	Treatment			Displacement		
Well	Volume (Barrels)	Average Rate	Maximum pressure	Volume (Barrels)	Average Rate	Maximum pressure
A-8	105	1.7 BPM	30 psi	125	1.6 BPM	480 psi
B-17	111	1.8 BPM	30 psi	120	0.8 BPM	170 psi

It is unknown why the injection pressure increased during displacement. Annular volume is about sixty barrels so it is not fill up. There are several possibilities of why pressure might increase including fines and particulates. Injection fluids were not filtered. So, it is likely to be particulates in the tank, where produced water was accumulated and stored for the treatment. After pumping Titan nutrients into the reservoir, the wells were shut-in for nine days to allow the microbial stimulation processes to proceed. The wells were returned to production on November 10, 2010.

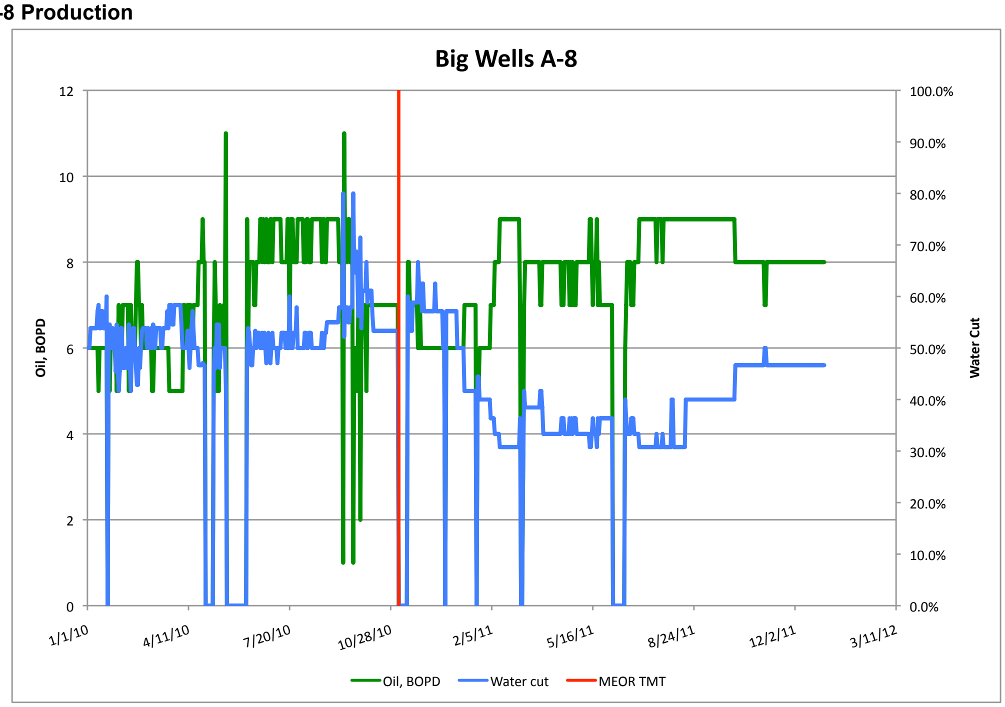
Microbial Response

Wellhead samples were collected from November 10, 2010 once the wells were put back on production. Samples were taken over four weeks of production. As production recommenced, reservoir and annulus fluids, nutrients and microbes move and mix. Early samples are representative of microbial activity in the wellbore, tubing and casing. Later samples are increasingly representative of the microbial interaction effects further from the wellbore. Overall, the number of microbes grown was greater than expected as the numbers exceeded those experienced in the lab. From a microbial perspective, the treatments were very successful. Duplication of lab results is the ultimate goal of this step in the process but precise replication is rarely obtained because conditions are far from ideal in the reservoir. Given the technical difficulty involved, the microbial response in these wells was outstanding. However, there remained the concern as to whether significant amounts of nutrients were able to penetrate the formation. There was also a concern in that there may not have been enough energy in the reservoir to move oil released by microbial stimulation caused by the injection of the nutrient mixture.

Production Results

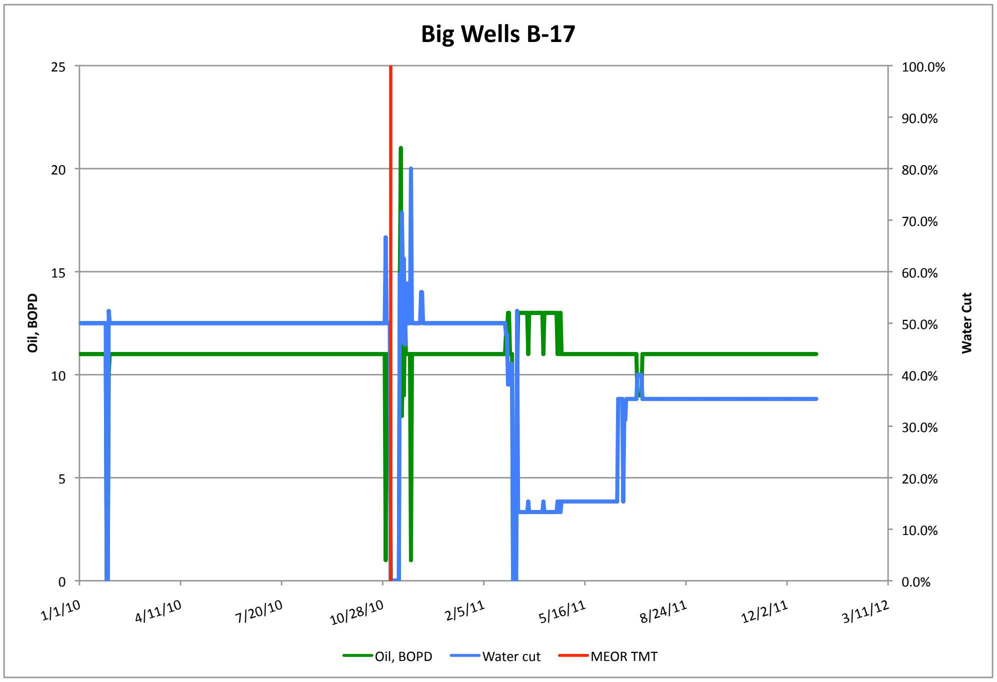
During the month prior to treating, Well A-8 produced an average of 7 BOPD + 8 BWPD, 53% water cut. Following the treatment, Well A-8 started to exhibit changing water cut performance in early January 2010. On January 9, it produced 7 BOPD + 5 BWPD, 42% water cut. Production slowly improved to 9 BOPD and 4 BWPD, 31% water cut in July. See Figure 1 for A-8 production. Because of this production response at A-8 additional produced fluid samples were requested from both wells. This is when the field reported that well B-17 was not making any water and a water sample could not be taken.

Figure 1. A-8 Production



Prior to treatment, Well B-17 was producing 11 BOPD and 11 BWPD, 50% water cut. Two days after being returned to production, Well B-17 showed a quick production peak of 21 BOPD + 18 BWPD, 46% water cut on November 15, 2010. This was a little surprising since a two-day shut in during January 2010 did not show any production increase. Within a week production settled down at 11 BOPD + 11 BWPD, 50% water cut until March when it was verbally reported not to be making any water. On March 11, 2011, B-17 was making 13 BOPD + 2 BWPD, 13% water cut. Its water cut has slowly risen since then.

Figure 2. B-17 Production

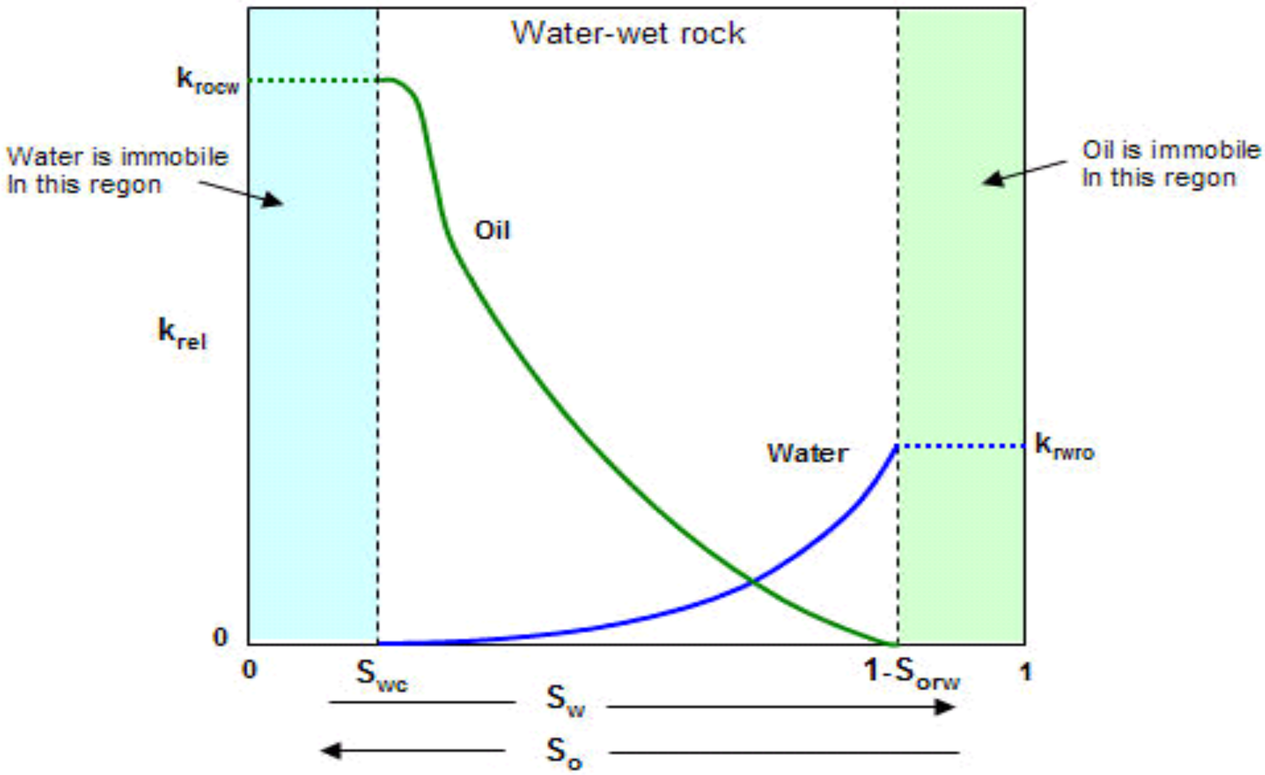


Discussion

Typically in a mature waterflood, oil occurs as isolated trapped immovable droplets that have little or no relative permeability to oil due to high in situ water saturation. Residue hydrocarbons tend to bond and coat the reservoir grains and act as pore-filling material. In a very mature waterflood, generally only water can flow toward the well bore (Schowalter 1999). The little bits of oil that are produced tend to be dragged to the producers as water moves through the pore channels.

As previously discussed, this organic oil recovery process releases oil that would normally be trapped within the reservoir. Although water cut changes have been reported previously in applications in California (Zahner 2010) and Saskatchewan (Town 2009), water cut in this application dropped to zero, albeit briefly. Despite the relatively low rate of production in this field (both oil and water), the authors believe that substantial oil was released near wellbore as a result of the nutrient treatment and this release of oil resaturated the producing channels in the reservoir rock. This resaturation of the reservoir changed the relative permeability of both the oil and water and resulted in lower water flow and improved oil flow. To increase the relative permeability to oil and decrease the relative permeability to water, the oil saturation would have to increase and the water saturation would have to decrease. See Figure 3, Relative Permeability Curve. To increase the relative permeability to oil enough to eliminate all water flow, the oil saturation would have to increase significantly. The very low reservoir energy prevented a more dramatic increase in oil production in this instance despite the apparent saturation changes. However, the oil release and change in relative permeability is significant in terms of the observed flow character as it might occur in other, higher-energy fields.

Figure 3. Typical Relative Permeability Curve[6]



Conclusion

The nutrient application targeting specific microbes was proven for this field in the successful application in two producing wells. These producer treatments confirmed the effectiveness of using nutrients in creating an effective biological response. The addition of nutrients was effective in creating long-term growth of desired microbial species and the creation of large numbers of hydrocarbon interacting forms of microbes. There is no doubt that the production response was a direct result of the nutrient stimulation even though the absolute volume of production was low. This is the first successful application of MEOR or organic oil recovery in a reservoir with permeability as low as 40 md.

Acknowledgements

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MEOR Success in Southern Saskatchewan

K. Town, Husky Energy, and **A.J. Sheehy** and **B.R. Govreau,** Titan Oil Recovery, Inc.

Summary

A microbial enhanced-oil-recovery (MEOR) process was successfully applied in a mature waterflooded reservoir in Saskatchewan, Canada. A nutrient solution, which was designed specifically for this reservoir to stimulate indigenous microbes to grow, multiply, and help to release oil, was tested and piloted. A significant decrease in water cut and increase in oil production have been realized through the selective stimulation of bacteria using nutrient injection.

The field is a mature waterflood averaging more than 95% water cut. To combat the increasing water-cut issue, an in-situ microbial response analysis (ISMRA) was performed on a typical high-water-cut producer in the area. The test well was treated with a nutrient solution and then was shut in for a number of days to allow indigenous microbes to grow and multiply. Upon return to production, the well produced at an average of 200% more oil with a 10% decrease in water cut for a year. Pretreatment rates averaged 1.2 m^3/d of oil (8 BOPD) and post-ISMRA treatment daily production peaked at 4.1 m^3/d of oil (26 BOPD). The ISMRA provides a direct support of laboratory studies and frequently increases oil production.

As a result of the successful ISMRA, a pilot project was initiated and the nutrients were applied in three batch treatments on an injector with three offset production wells. Three weeks after the first batch treatment, a water-cut decrease was seen at one of the offset producers. This well's oil production gradually increased from 1.4 to more than 8 m^3/d (9 to 50 B/D). Oil production in another producer doubled from 1.5 to more than 3.0 m^3/d (9 to 19 B/D). Subsequent treatments were tried on marginally economic wells and on a reactivated idle producer. The average decrease in water cut in these wells was more than 10%. On the idle well, oil production increased from 0.5 m^3/d (3 B/D) pretreatment to an average of 3.0 m^3/d (19 B/D) post-treatment.

Throughout the world, there remains a huge target for enhanced-oil-recovery (EOR) processes to target (Bryant 1991). This successful MEOR application will have a tremendous impact on ultimate recovery in many of these reservoirs not only through an increase in production, but a decrease in operating costs through associated reduction in lifting costs with less water production.

Introduction

Trial Field. The trial field is located in the southwest corner of the province of Saskatchewan, Canada, southwest of Swift Current. The trial field produces from the Upper Shaunavon sand. The field was discovered in 1952, and the waterflood was started in approximately 1967, initially set up as an inverted-five-spot pattern on 80-acre spacing.

The Upper Shaunavon sits on a structural high and has three members. The upper member is very high quality sand and an excellent reservoir. The middle member, a poorer quality sand than the upper member, is isolated from the upper member. The lower member is a tight mixture of sands and shales. The average porosity ranges from 21.5% in the upper member to 15.2% in the lower member. The average permeability ranges from 567 md in the upper member to 53 md in the lower member. The average net pay is 2.6 m (8.5 ft) in the upper member, 1.8 m (5.9 ft) in the middle member, and 1.4 m (4.6 ft) in the lower member. Reservoir temperature is 47°C (117°F). Reservoir depth is 1200 m (3,927 ft). Total dissolved solids of the produced water are 10025 mg/L.

Cumulative oil production is 3.3 million m^3 (21 million bbl), with average recovery of approximately 29% of the original oil in place. Like most waterflooded reservoirs, low recovery makes the Upper Shaunavon an ideal EOR candidate. Oil gravity is 22–24°API. Current oil production is 62 m^3/d (391 B/D), with 1300 m^3/d of water (8,190 BWPD) and 4250 m^3/d of gas. Current injection is 1700 m^3/d (10,700 BWPD).

The MEOR Process. MEOR is a group of processes based on increasing oil recovery by use of bacteria. In general, the mechanisms can be grouped into those which alter oil, water, reservoir, or interfacial properties, usually through mimicry of chemical EOR processes and those that use the biological mass (biomass) for flow diversion (Gao 2009). MEOR traditionally has involved the injection of particulate bacteria and the food they need to generate the EOR chemical or biomass.

There are very few documented applications of successful MEOR projects in waterfloods. Most successful MEOR applications are single-well treatments that would be better described as wellbore cleanup. Although the first evaluation of this process was on a production well in the Alton field in Australia (Sheehy 1990), this process targets mature oil fields currently using conventional water-injection (waterflood) operations as a means of secondary recovery. Unlike previous attempts at MEOR, this process does not attempt to introduce microbes into the oil-producing reservoir. Instead, through a sophisticated analysis of field-specific crude oil and water, microbes that are naturally indigenous to the oil reservoir are identified and quantified (Davis 2009). On the basis of laboratory techniques, analysis, and specific field-test procedures, a "designer mixture" of naturally occurring nutrients is formulated and released into the reservoir by means of the water-injection system. Although the nutrient additives are proprietary, the nutrient mixture is made up of a solution of salts, ammonium nitrate, and organic compounds. The water-injection system becomes the transport medium for the designed nutrient formulations. The reservoir is treated with a targeted and unique nutrient formula. The process is designed for crude-oil production and is not currently suitable for either natural-gas or condensate fields, nor is poorly mobile oil currently a target of this process. Certain species of resident microbes have a cellular change resulting in an affinity for oil instead of water. Attracted to oil, these resident microbes move to and insert themselves into the oil/water interface around any trapped oil in the reservoir. The flow characteristics of the trapped oil are affected by the presence of microbes at the oil/water interface. The changes in the oil/water/rock/bacteria interfaces result in the deforming of the residual oil, allowing small droplets to form and be released into the active flow channels of the reservoir. **Fig. 1** shows how microbes work at the oil/water interface to help release oil. In very highly permeable portions of the reservoir ("thief zones"), newly released oil, water, and microbes can interact to form a transient (temporary) microemulsion, which effectively alters the sweep efficiency of the injected water as it moves through the reservoir to improve current production and ultimate recovery.

Reservoir Screening and Laboratory Work

The reservoir parameters were reviewed to determine if this reservoir is a good candidate for MEOR. There are two main criteria for a good candidate reservoir: mobile oil and the presence of specific species of microbes. In spite of relatively low oil gravity in the target field, the reservoir had good waterflood response, indicating

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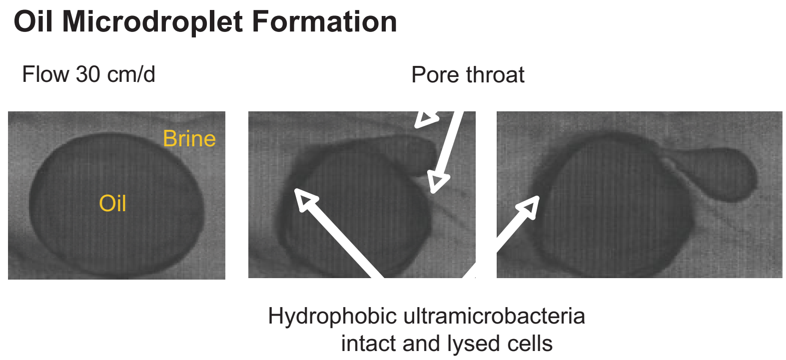

Fig. 1—Oil-release process: Microbes migrate to the oil/water interface to help break up the oil.

that the oil is mobile. With the reservoir's moderate temperature of 47°C (117°F) and with produced water with only 9500 mg/L of chlorides, it was very likely that microbes were present in the reservoir. Laboratory analyses of bacterial growth were conducted on the samples of produced water. Incubations were established with a range of nutrients and concentration of nutrients. The samples were examined by microscopy for evidence of cellular changes. Bacterial-growth patterns and replication rates consistent with the nutrients used as supplements were observed. Equally important, the nutrient manipulation resulted in the growth of a subpopulation of bacteria capable of interaction with the oil/water interface. Specific nutrient combinations resulted in optimal potential for oil recovery and were recommended for use in this reservoir.

Field Application

The application of MEOR to the field has been performed in stages. First, the nutrients developed in the laboratory were used in treating a producing well. When the appropriate microbial response was observed, the second step was to treat an injection well. Since these were both successful, additional applications are being administered in both producers and injectors. A description of each step and the result of each step follow.

ISMRA. Once laboratory work is complete, the formula devised specifically for this reservoir is applied to a producing well in a cyclic treatment. This is called ISMRA and is done mainly to confirm that the appropriate microbes are stimulated. **Table 1** gives details of the number of bacteria, bacterial biodiversity, and the proportion of hydrophobic bacteria present. Results are semiquantitative for presentation purposes.

Pretreatment samples showed a low number but diverse range of resident bacteria. Very few of these were hydrophobic oil-interactive forms. After nutrient treatment, the number of bacteria and number of oil-interactive forms increased dramatically. However, the biodiversity decreased because of the selective nature of the nutrients used.

The post-treatment samples showed the emergence in the field of hydrophobic oil-interactive forms. There was a substantial similarity between the bacterial-growth patterns observed in the laboratory and from post-ISMRA produced-water samples. Overall, post-treatment samples may produce different population sizes compared to the laboratory, but the ratio of hydrophobic to total bacteria remains constant.

Often this treatment also results in an increase oil production. On 6 December 2007, ISMRA was performed on Well A in Trial. A 1.3-m^3 (8-bbl) tote of chemical nutrients solution was mixed with 13 m^3 (82 bbl) of injection water. The nutrient solution was injected into Well A through the tubing-casing annulus and displaced with 27 m^3 (170 B) of injection water. Well A was then shut-in for 7 days to allow specific indigenous microbes to grow and multiply as a result of the nutrient stimulation. On 13 December, Well A was returned to production. Results were encouraging. The targeted species of microbes grew and reproduced exceptionally well. Also, oil production increased, with an associated decrease in water cut. Pretreatment daily production average for Well A was 1.2 m^3 of oil (8 BOPD) and 20.8 m^3 of water (131 BWPD), a 94% water cut. Post-ISMRA-treatment daily production peaked at 4.1 m^3 oil (26 BOPD) and 19.0 m^3 of water (120 BWPD), an 80% water cut. Well A is still seeing incremental production with current daily production of 2.2 m^3 oil (14 BBL) and 21.0 m^3 water (132 BWPD), a 91% water cut. There was no change in the character of the produced fluid reported, and no treating problems were noted. This single-producing-well application result exceeded expectations by delivering approximately 500 m^3 (3,150 bbl) of incremental oil. The water cut, percent water produced,) also decreased significantly, which was another positive result of the treatment from an operating perspective. See the production graph in **Fig. 2.**

Pilot. Now that the nutrients had been proved to be appropriate for this reservoir, a pilot project was initiated. Injection Well B was chosen for the pilot. It has three offset producers, Wells C, D, and E. The pilot area is depicted in **Fig. 3.** The intent of this pilot test is to document the production response from the application of the MEOR process. In addition to a production increase, a microemulsion may form in the reservoir, which will manifest itself at surface with lower injectivity in the pilot injector. The injection rate has been maintained on Injector B, and there has been no change in injectivity, which implies that no emulsion has formed. Also, there has been no indication of a microemulsion forming in the produced fluids **(Fig. 4).**

The injector was batch treated with the nutrient solution, which was pumped down the injector and displaced into the reservoir

TABLE 1—WELL A COMPARISON OF BACTERIA RESULTS

Well	Number of Bacteria	Bacterial Biodiversity	Hydrophobic Bacteria
Pre-ISMRA no nutrients	+	++ to +++	+/–
Pre-ISMRA with nutrients	++++	++	++++
Post-ISMRA 30 minutes	++++	+	++++
Post-ISMRA 3 days	++ to +++	++	+++
Post-ISMRA 5 days	++ to +++	+++	+++

+/– Sparse; + few; ++ moderate; +++ many; and ++++ numerous.

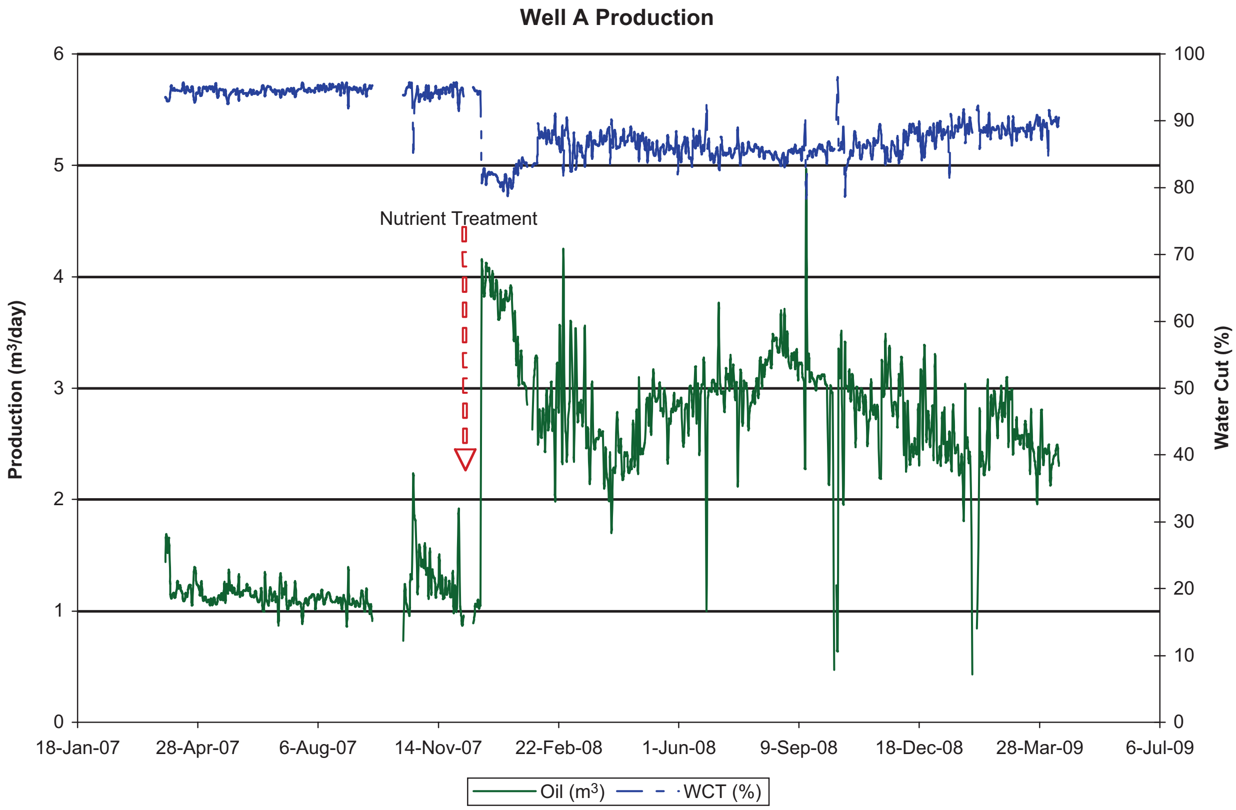

Fig. 2—Producing Well A responds to cyclic treatment of nutrients.

with an additional 200% of the tubing volume of injection water. On 24 April 2008, Injector B was treated with a 1.3-m^3 (8-bbl) tote of chemical-nutrient solution, which was mixed with 16 m^3 of injection water. After being injected, the nutrient solution was displaced with 32 m^3 (200 bbl) of water. Allowing the microbes time to incubate and populate, injection into Well B was limited for the next 8 days. Injected volumes were 10, 20, 50, and 75% of normal injection across the 8-day period.

After the nutrient injection, wellhead samples from the first offset production wells of the treated injector were taken and analyzed in the laboratory. Samples were tested by culturing and analyzing to determine changes in microbial composition and growth. The producers were monitored continually for rates, fluid levels, and produced-water chemistry. From this information, the coordination and scheduling of additional treatments were determined. Subsequent batch treatments were conducted on 29 July and 3 December 2008.

On 10 May Well C increased from daily production of 1.5 m^3 of oil (9 BOPD) and 50.2 m^3 of water (316 BWPD), a 97% water cut, to 4.6 m^3 of oil (29 BOPD) and 51.8 m^3 of water (326 BWPD), a 92% water cut. Production continued to improve and the well peaked at 10.0 m^3/d of oil (63 bbl) and 68.0 m^3 water (428 BWPD), an 87% water cut. First response was expected in Well C because it is the nearest adjacent producer and it produces the most fluid. Current production shows a 350% increase in oil production and an 8% decrease in average water cut. Laboratory analysis shows that the targeted species of microbes grew and reproduced exceptionally well in Well C. Many microbes were in their hydrophobic state, in which they move to the oil/water interface and help to release additional oil **(Fig. 5).**

Gradually, positive response has been seen in the E offset producer. Starting at daily production of 1.5 m^3 oil (9 BOPD) and 25 m^3 of water (158 BWPD), a 94% water cut, daily production peaked at 3.0 m^3 of oil (19 BOPD) and 38.3 m^3 of water (241 BWPD), a 93% water cut. Current production is 1.9 m^3/d of oil (12 BWPD) and 36.8 m^3 water (232 BWPD), a 93% water cut **(Fig. 6).**

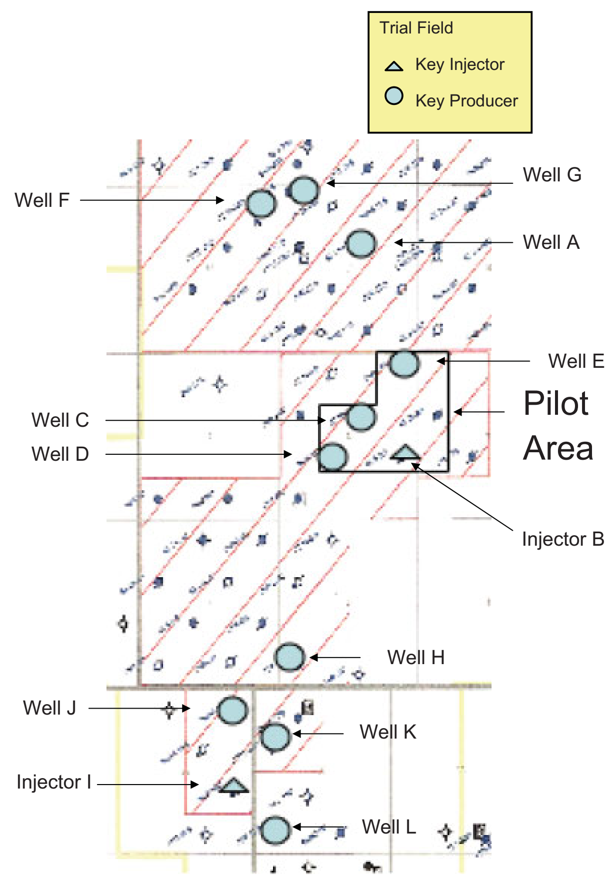

Fig. 3—Partial field map.

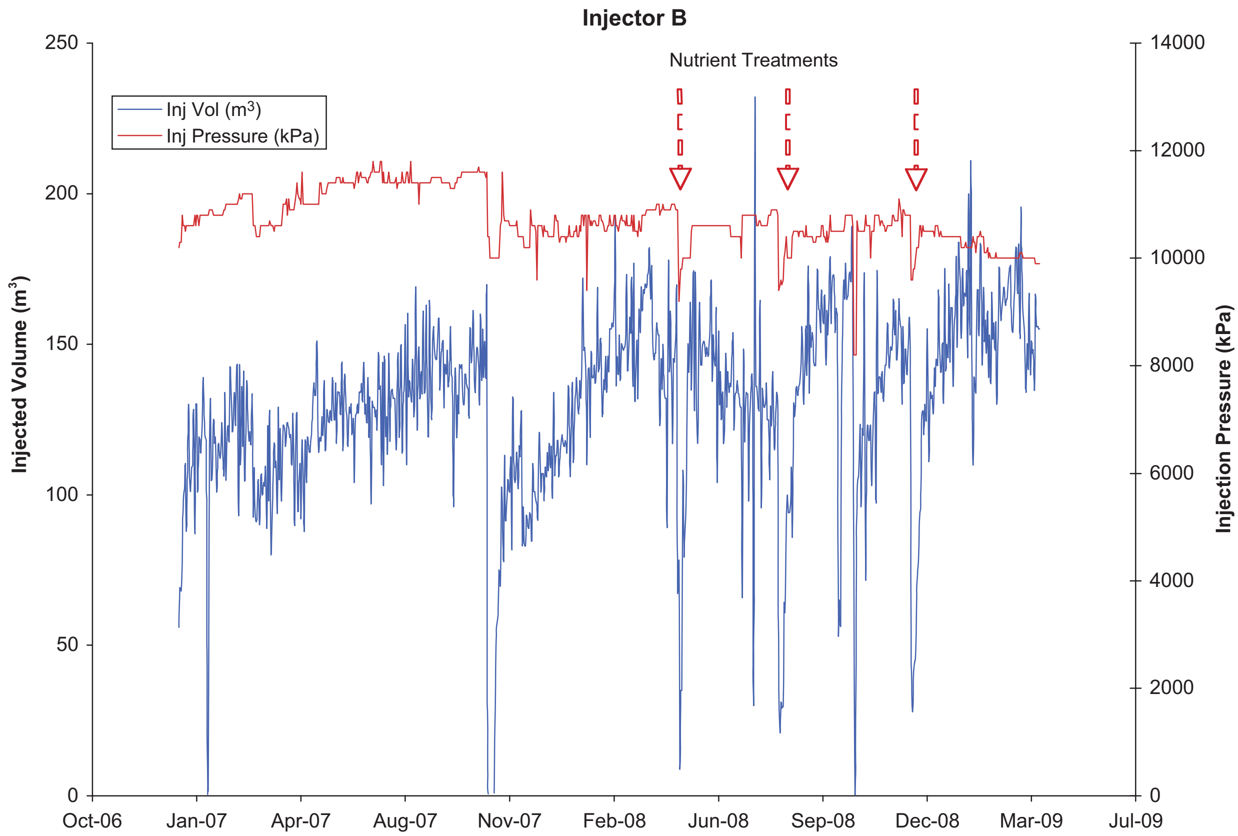

Fig. 4—Injection rate at Well B, the pilot injector, is maintained.

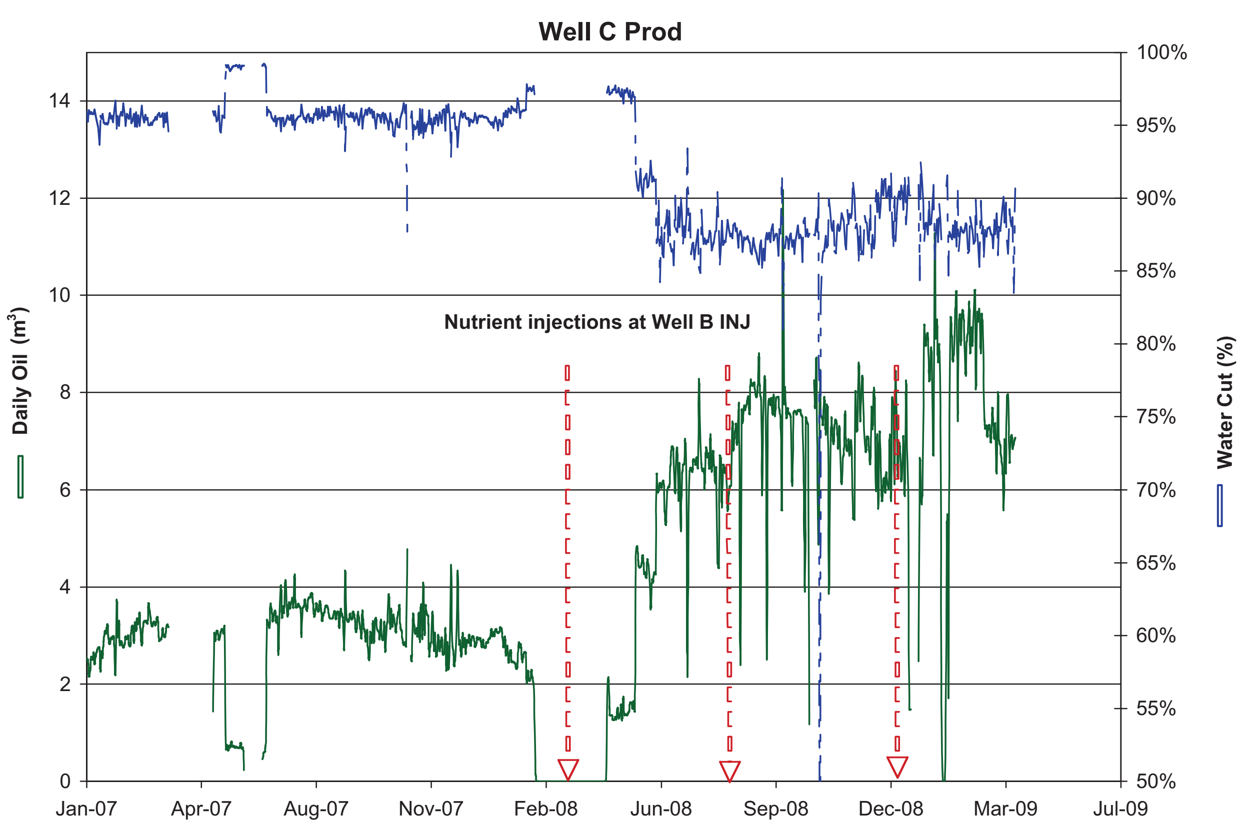

Fig. 5—Producing Well C responds to treatments in offset Injector B.

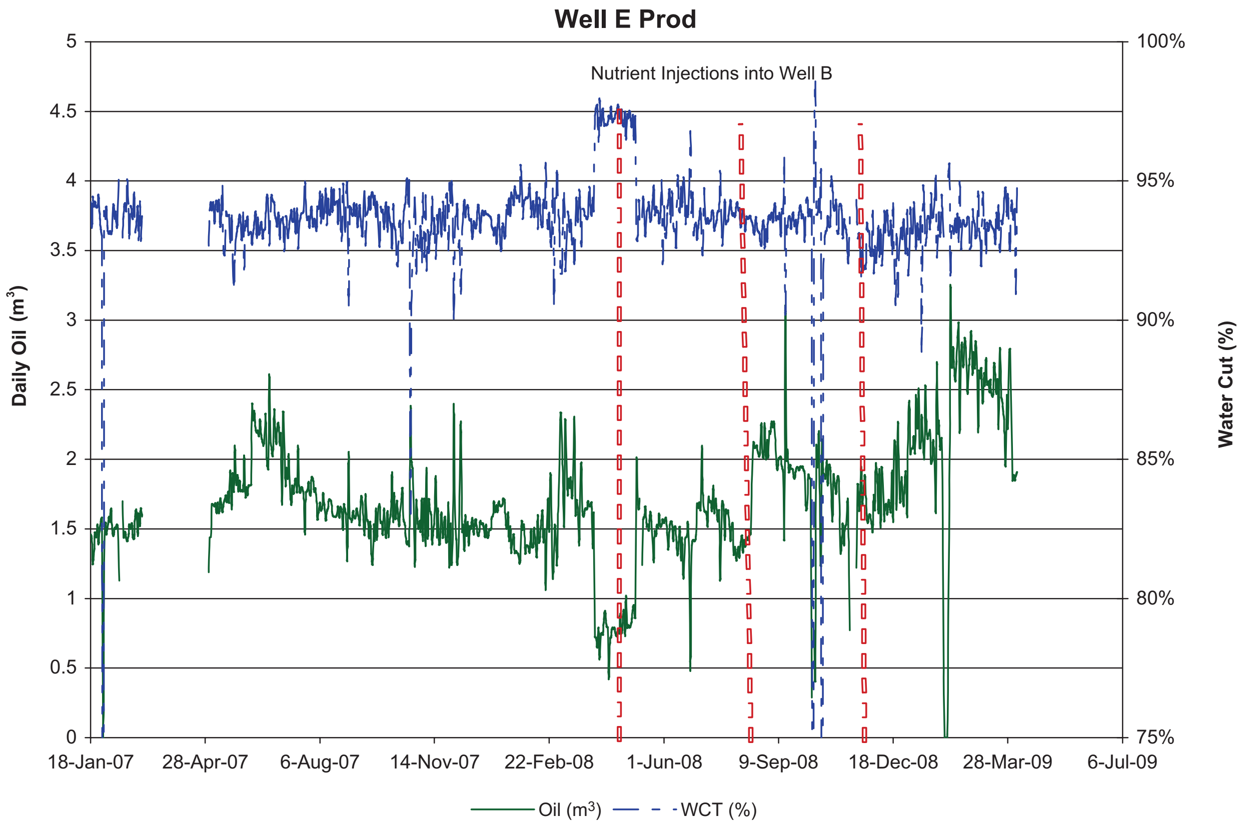

Fig. 6—Producing Well E responds to treatments in offset Injector B.

To date, no response has been seen in the other offset well, Producer D. This is not a surprise because transit time from Injector B is very likely to be longer, on the basis of well location, reservoir volume, and injection conformance. Well D daily oil production remains at 0.5 m^3/d of oil (3 BOPD) and 1.5 m^3/d of water (9 BWPD). Laboratory analysis of produced fluids from Well D indicates that only a small number of microbes are present. The low microbe concentrations in Well D indicate that the nutrient effect has not yet reached this producing well.

Additional Producer Applications. As a result of the magnitude of oil response seen in the ISMRA treatment on Well A, subsequent producer treatments were performed. On 25 April 2008 MEOR treatments were performed on Wells F and G. Well F had been idle since 2005 and was reactivated to see what effect a nutrient treatment would have on a reactivated well. Because the microbes did not respond with the first treatment, Well F was retreated on 27 July. Then on 4 December 2008, a treatment was performed on Well H. In each case, a 1.3-m^3 (8-bbl) tote of chemical-nutrient solution was mixed with 13 m^3 (82 bbl) of injection water through the tubing/casing annulus and displaced with injection water. The test well was then shut in for 7 to 10 days to allow specific indigenous microbes to grow and multiply as a result of the nutrient stimulation.

Of the three production wells treated, Wells F and G have shown exceptional response. Well F increased from 0.6 m^3/d of oil (4 BOPD) and 3.2 m^3/d of water (20 BWPD), an 84% water cut to 4.1 m^3/d of oil (26 BOPD) and 4.6 m^3/d of water (29 BWPD), a 53% water cut. Well G averaged 0.5 m^3/d of oil (3 BOPD) and 30 m^3/d of water (189 BWPD), a 98% water cut, before the second treatment, which was very similar to the 0.5 m^3/d of oil (3 BOPD) and 25 m^3/d of water (158 BWPD), a 95% water cut that it was yielding in July 2005 when it last produced. After the second treatment, the well peaked at 3.0 m^3/d of oil (19 BOPD) and 20.8 m^3/d of water (131 BWPD), an 87% water cut.

Even though initial oil production was disappointing, there was an excellent microbial response in Well H. It is believed that the lack of increased oil production is a result of other reservoir conditions. See **Figs. 7 through 9** for production curves of all three production wells, respectively.

Expanding the Pilot. After seeing the response in the pilot area, it was decided to apply the MEOR process to a second injector. A batch treatment was pumped into Injector I on 4 December 2008. As in the pilot, an oil-production increase was seen approximately 3 weeks after the first injection of nutrients. The three offset producers, Wells J, K, and L, responded. In total, they have increased production from 10.2 m^3/d of oil (64 BOPD) and 157 m^3/d of water (989 BWPD), a 94% water cut to a peak of 16.7 m^3/d of oil (105 bbl) and 151 m^3/d of water (951 BWPD), a 90% water cut. See **Figs. 10 through 12** for the individual production curves.

Discussion

The trial field is experiencing several economic improvements. Not only is there an increase in oil production, but also there is an increase in oil recovery. With the increasing oil production and decreasing water cut, lifting costs are reduced. All these factors contribute to extending the life of the field. As in this application, a reduction in water production is often seen with these nutrient treatments. For instance, on ISMRA Well A, water production dropped from 20.8 m^3/d (131 BWPD) to 19 m^3/d (120 BWPD). It is believed that the changes to the oil/water/bacteria interface in the wellbore region change the relative permeability of water and oil. Because the MEOR nutrients stimulate microbes that compete with sulfate-reducing bacteria, a reduction of sulfide may be experienced. Some governments have programs in place to encourage EOR projects. This project is benefiting from provincial-government support to apply a new process.

There are several advantages of this process over other EOR processes, and even over other MEOR processes. It is low cost to implement. Average incremental cost per barrel in the trial MEOR application has been USD 6.00 (USD 37.73/m^3). There is

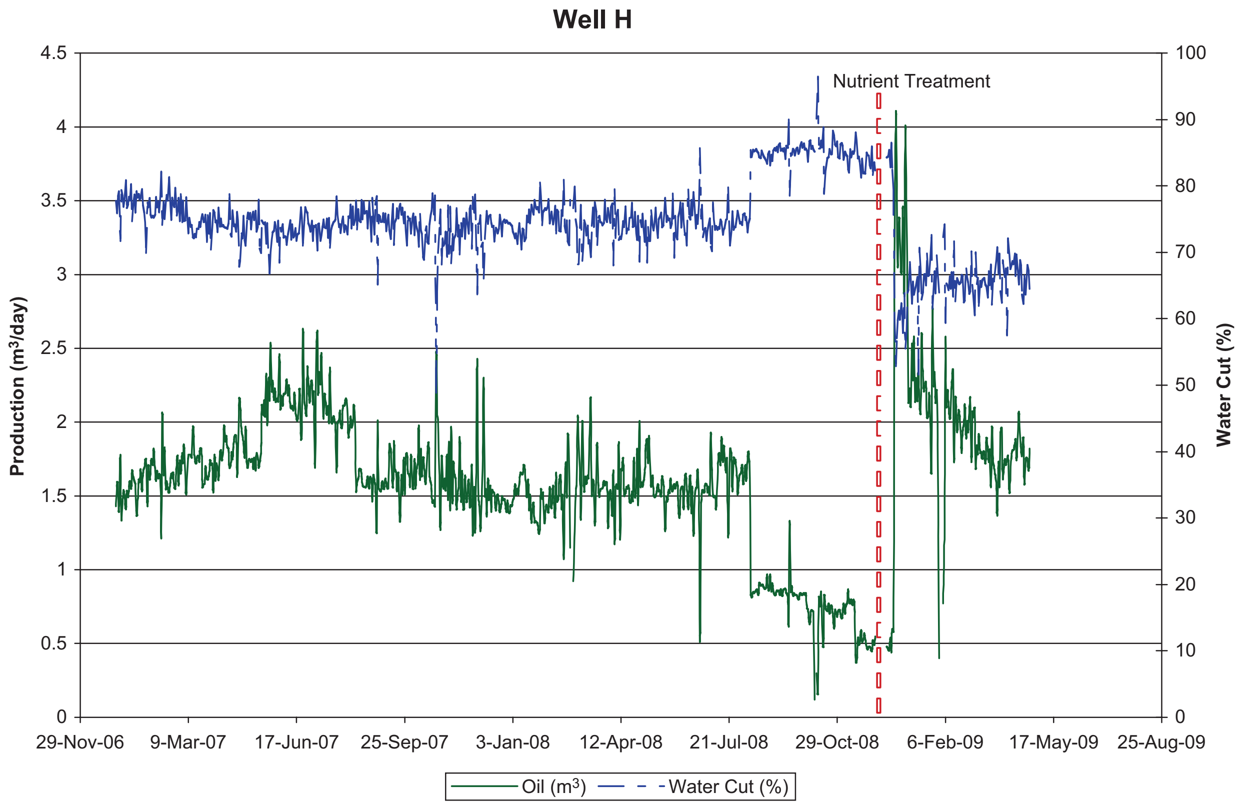

Fig. 7—Producing Well H responds to cyclic treatment.

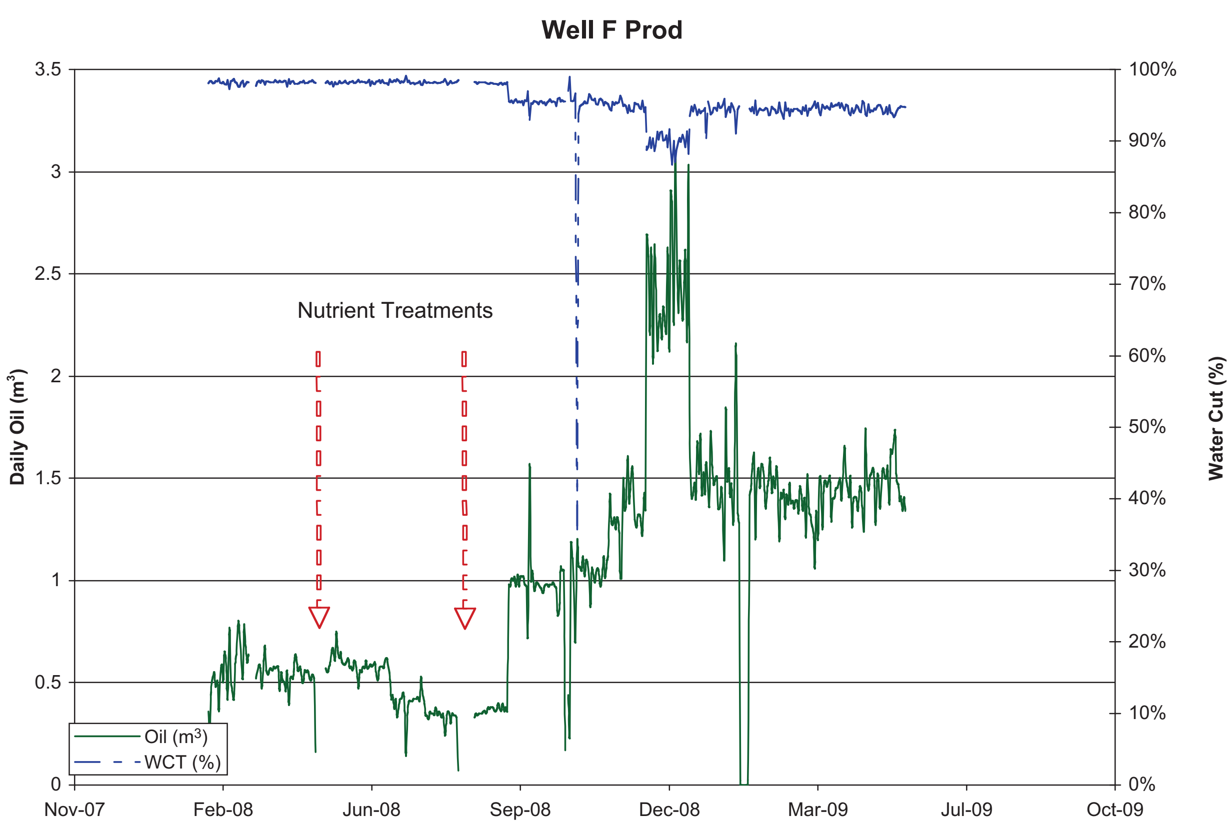

Fig. 8—Idle F producer is reactivated and treated with nutrients.

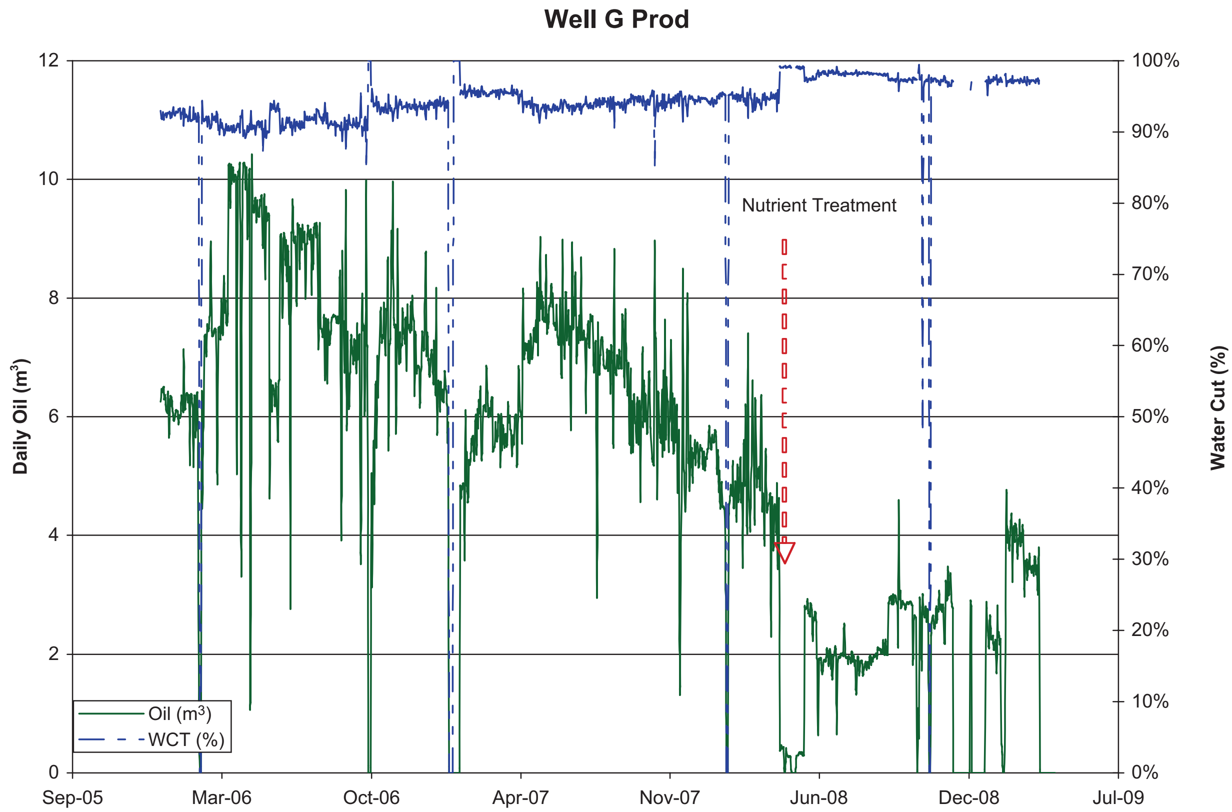

Fig. 9—Producer G is treated with nutrients.

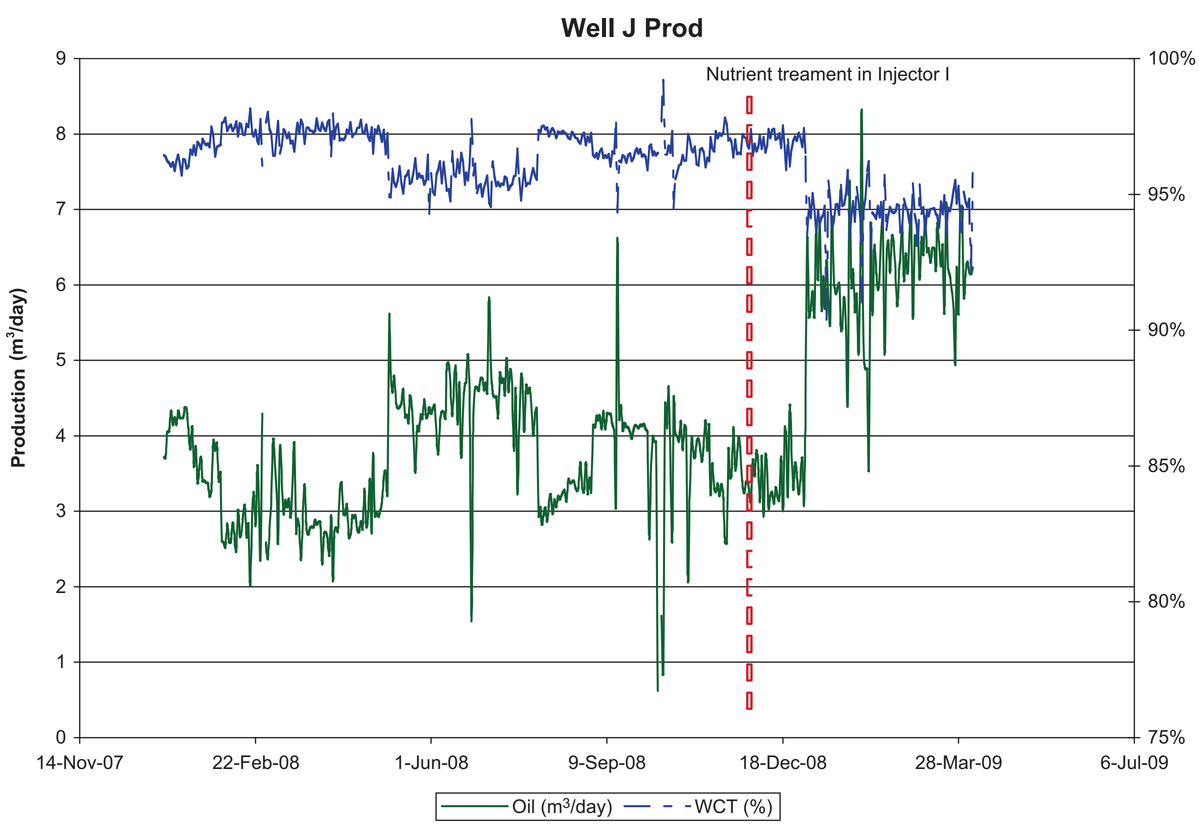

Fig. 10—Producer J responds to treatment in offset Injector I.

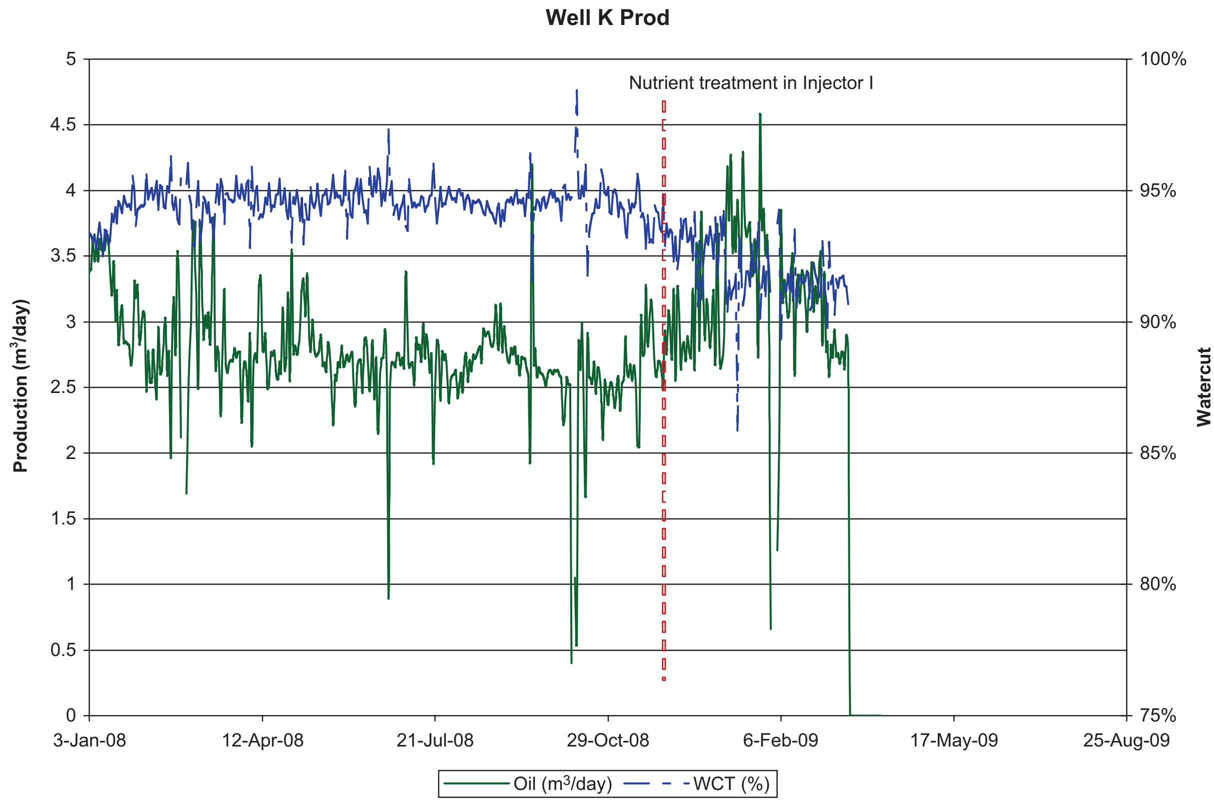

Fig. 11—Producer K responds to treatment in offset Injector I.

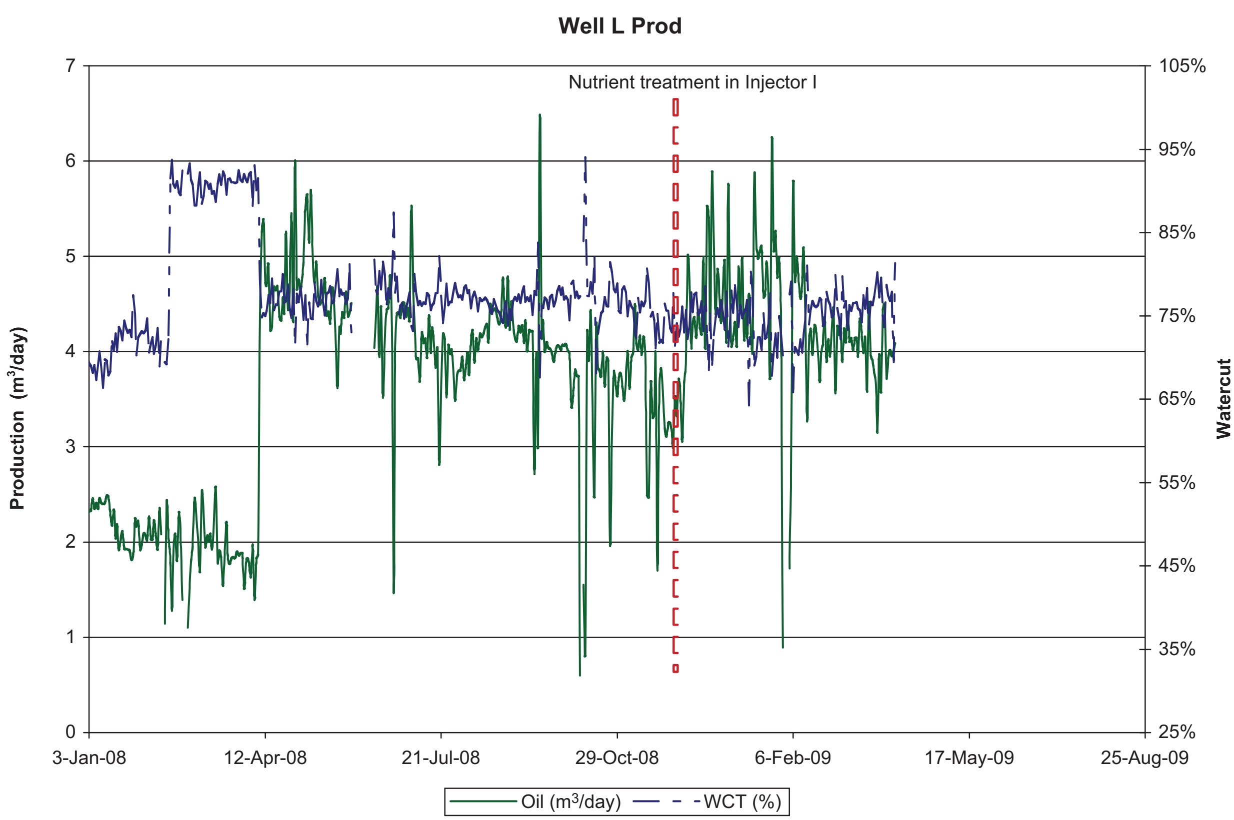

Fig. 12—Producer L responds to treatment in offset Injector I.

no capital outlay required to implement a project. Since the nutrients are batch treated even in injectors, permanent equipment is not required. There is little cost required to test the concept. Costs to conduct laboratory testing and to test nutrients in the field are minimal. Also, with batch treatments, the impact on field personnel is minimal. Another advantage is that it is low risk to implement. No microbes are injected, which minimizes the potential to cause reservoir plugging. The nutrient solutions that are injected are environmentally benign.

Future Plans

It is planned to expand the MEOR application throughout the entire field. Both injectors and producers can be treated to capture commercial quantities of oil. On the basis of response, the frequency of treatments will vary. For producers, frequency could be anywhere from 6 months to 2 years. For injectors, it could be as often as every 4 weeks or as widely spaced as every 4 months, depending on field performance. It is recognized that microbial response will likely vary from location to location throughout the field and that the response time to the treatment will also vary as water transit times change with varying water-injection conformance.

Acknowledgments

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Krista Town is area engineer for the southern Alberta and southern Saskatchewan assets of Husky Energy in Calgary. She holds a BS degree in chemical engineering from the University of Saskatchewan with biochemical option. **Alan Sheehy** is vice president and principal scientist for Titan Oil Recovery and professor of microbiology, Microbiology Research Unit, University of the Sunshine Coast in Queensland, Australia. He is a microbial ecologist specializing in extractive industries especially oil and gas. Sheehy's appointments include inaugural dean of science and professor of microbiology at the University of the Sunshine Coast, professor of microbiology at the University of Canberra, and senior principal research scientist at the Commonwealth Scientific and Industrial Research Organization of Australia (CSIRO). **Bradley Govreau** is chief operating officer for Titan Oil Recovery. E-mail: bgovreau@titanoilrecovery.com. He holds as BS in petroleum chemical engineering from Louisiana State University. Govreau has 30 years of oil, gas, and geothermal operations experience with Unocal.

SPE Paper 129742

MEOR Success in Southern California

Bob Zahner, Venoco Inc.; Alan Sheehy and Brad Govreau, Titan Oil Recovery, Inc.

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Abstract

A Microbial Enhanced Oil Recovery (MEOR) process was successfully applied to a mature waterflood in Southern California, using indigenous microbes that normally remain dormant during the producing life of the field. Certain indigenous microbial species can be activated in waterflood reservoirs by introducing the correct blend of nutrients. Once activated, the microbes multiply when the nutrients deplete, then migrate to immobile oil in search of a food source. The microbes break up this residual oil saturation into smaller micro-droplets that can flow through pore throats and be swept to producers, yielding an increase in oil recovery. The application on a producing well led to an increase in well tests from 20 to over 80 BOPD. Following this encouraging test, the nutrients were applied in three batch treatments on each of the waterflood injectors. At peak response a thirty percent oil rate increase was seen in the offset producers. Because this process uses indigenous microbes, there are no compatibility issues with reservoir fluids or concerns about survival in a foreign environment. The results from this field application demonstrate that managing a reservoir's indigenous microbes can yield significant incremental oil production in a mature waterflood with a minimal investment.

Introduction

The Beverly Hills field has two major producing horizons, the Hauser and the Ogden. The Hauser has been waterflooded since the mid-1980's, although producers in the field are commingled in both the Hauser and the Ogden formations. All water injection is into down-dip Hauser completions on the northeastern flank of the reservoir in the proximity of the original oil water contact. Oil gravity averages 22.5° and ranges from 22 to 26° API. The field has fourteen active producers and three active injectors with well spacing of approximately 10 acres. Field production is currently about 400 BOPD, 2,000 BWPD and 300 MCFD (Figure 1). All produced water is reinjected into Hauser (Figure 2).

The results reported in this paper are based on well tests. Allocation of metered oil from the lease by well test is usually within 10% of the well tests. As in many fields, water cut data is limited as there is no provision for continuous sampling during well tests. Water cuts are based on wellhead samples taken by hand while the wells are being tested.

Oil Release Mechanism

Unlike many previous attempts at MEOR, this process does not attempt to introduce microbes into the oil-producing reservoir (Sheehy, A. 1990). Instead, through a sophisticated analysis of field oil and water, microbes that are naturally indigenous to the oil reservoir are identified and quantified. Based on laboratory analysis, a reservoir-specific mixture of environmentally benign nutrients is formulated and released into the reservoir via water injection. The water injection becomes the transport medium for the designed nutrient formulations. The reservoir is treated with a targeted and unique nutrient formula. By activating certain species of microbes, changes in the flow characteristics of the oil are affected and induce the reservoir system to release additional oil to the active flow channels (Town, K. 2009). In higher permeable portions of the reservoir, newly released oil, water and microbes may interact to form a transient (temporary) micro-emulsion which effectively alters the sweep efficiency of the injected water as it moves through the reservoir to improve current production and ultimate recovery. In a waterflood, this process can recover up to an additional 10% of the original oil in place. (Davis C. P. 2009)

Steps in the MEOR Process

The Beverly Hills Field MEOR treatment program began in 2007. The application of this process typically consists of five steps: 1) Initial field screening, 2) Well sampling and laboratory analysis, 3) In-situ Microbial Response Analysis (ISMRA), where the nutrient formula developed in the lab is applied to a producing well to determine the microbial response is maximized, 4) Pilot testing (if applicable) and 5) Full-field application. In this case the ISMRA, a single nutrient application in the producing well, was performed on well OS-1. Because this field only has three injectors, the pilot was skipped and full-field application immediately followed the successful ISMRA. The application was expanded to the full-field by performing nine water injection well treatments in the three active injection wells, OS-9, OS-10 and OS-14 and two additional producing well treatments, OS-8 and BH-15. See Field Diagram, Figure 3

ISMRA Treatment Specifics

With a nutrient solution designed from the laboratory analysis of the field produced fluid samples, the ISMRA was conducted on producer OS-1 on July 2, 2007. A small volume (less than 8 barrels) of nutrients was injected into the well to check the reaction and behavior of in-situ microbes in the reservoir. The nutrient concentrate was mixed with 100 barrels of produced water and displaced with 350 barrels of injection water. The well was then shut-in for three days to allow targeted indigenous microbes to grow and multiply as a result of nutrient stimulation.

Pretreatment production from OS 1 was 20 BOPD and 95 BWPD. After peaking at 130 BOPD and 32 BWPD, well tests average 82 BOPD and 80 BWPD for the first three months after treatment as shown in Table 1.

Table 1. OS 1 Well Test Data

	Date	Gross	Cut	Water	Oil
Well Tests before Treatment					
(Normal well production)	3/6/07	110	87	96	14
	3/11/07	105	82	86	19
	3/28/07	130	79	102	28
	Average:	**115**	**83**	**95**	**20**
Well Tests after Treatment	7/9/07	177	56	99	78
	7/17/07	182	50	91	91
	7/24/07	162	57	92	70
	8/6/07	162	20	32	130
	8/14/07	156	61	95	61
	9/4/07	158	66	104	54
	9/26/07	134	34	44	88
	Average:	**162**	**49**	**80**	**82**

Over a year later, OS-1 was still producing 33 BOPD and 80 BWPD, although production was likely supported by treatment of offset injection wells as described in this paper. This single producing well application yielded over 3,000 barrels of incremental oil with a decrease in water produced (Figure 4).

Injection Well Treatments

Following the extraordinary performance of this initial application, the project was expanded to the full field by treating the field's three water injection wells, OS-9, OS-10 and OS-14, with three treatment cycles each for a total of nine treatments over a seven-month period from November 2007 to May 2008. On November 29, 2007, an 8-barrel tote of highly concentrated chemical nutrient solution was mixed with 250 barrels of injection water, injected into well OS 9 and displaced with 250 barrels of water. Giving the microbes time to incubate and populate, the water injection rate into OS-9 was limited for the next 8 days. Each injector was given three similar treatments on the schedule listed below.

Well	Injector Batch Treatment Dates
OS-9	November 29, 2007, January 11 and March 20, 2008
OS-14	December 20, 2007, February 16 and April 15, 2008
OS-10	January 31, March 1 and May 1, 2008

Between July and September 2008 oil production increases were seen in the five active front-line producers, OS-1, OS-3, OS-4, OS-12 and OS-13. The targeted species of microbes grew and reproduced as nutrients migrated from injector to producer, freeing oil along the way.

Produced fluid samples taken on June 12 from the front line producing wells indicated high concentrations of microbes were present in four of the five adjacent producers, OS-1, OS-3, OS-4 and OS-13. This was consistent with improved well tests seen on these four wells. The June 12 sample taken from OS-12 did not show any microbe activity, which was consistent with its well tests at the time. In July, OS-12 experienced a jump in oil production and another produced fluid sample was taken in August to determine if the oil production increase was coincident with improved microbial activity. Laboratory results confirmed an increase microbial response with the increased oil seen in the well tests.

The front line producers made more oil as a result of these treatments. From June through August 2008, the first 3 months of response, the front line producers averaged 206 BOPD and 1,480 BWPD. These wells averaged 179 BOPD and 1,490 BWPD from March to May. Also, base production estimated in January of 2008 for these wells was 179 BOPD. These wells produced an average 27 BOPD over their base for the three months, June to August 2008 (See Figure 5). The front line producers averaged 217 BOPD in July. The well tests peaked at 232 BOPD and 1,669 BWPD. This is 53 BOPD over the base of 179 BOPD, a 30% increase. The front line producers accumulated about 2,500 barrels of incremental oil through August. As a result of these treatments, incremental oil continued to be produced above the baseline.

Based on the improved well tests and the advance seen in microbe activity in the other front line producers, well OS-2 was returned to production on June 18, 2008. It had been shut in since April 2003 when it tested 2 BOPD and 217 BWPD. It tested no oil until November 2008 when it tested 11 BOPD and 142 BWPD. Well tests eventually peaked at 46 BOPD and 243 BWPD after the well's lift equipment was optimized (Table 2).

Table 2, OS 2 Well Tests

Well ID	Date	BOPD	BWPD	MSCFD	%WC
O.S. 2	4/17/03	2	217	0	99%
	6/18/08	RTP			
	7/9/08	0	180	0	100%
	7/21/08	0	166	0	100%
	8/19/08	0	128	3	100%
	9/22/08	0	99	1	100%
	11/19/08	11	142	2	93%
	11/21/08	13	132	2	91%
	12/3/08	8	160	5	95%
	1/10/09	10	191	5	95%
	2/9/09	8	150	4	95%
	3/28/09	20	158	5	89%
	5/17/09	6	185	5	97%
	5/20/09	46	243	5	84%
	5/22/09	20	222	5	92%
	5/23/09	42	222	5	84%
	5/27/09	29	235	5	89%
	5/28/09	15	238	5	94%
	5/30/09	26	236	5	90%
	7/9/09	33	224	5	87%
	7/20/09	25	221	10	90%
	8/13/09	23	203	10	90%
	8/25/09	2	234	18	99%
	9/24/09	31	228	18	88%
	10/8/09	22	250	18	92%
	11/6/09	22	226	10	91%
	12/17/09	16	66	10	80%
	1/15/10	31	224	12	88%

Because all the completions commingle Ogden and Hauser production, it was decided to do some zone isolation work to determine the source of oil. The Ogden and Hauser zones were isolated and swabbed separately in both OS-2 and OS-3 during routine well service jobs, with similar results. The swab tests indicated that most of the oil is currently produced from the Ogden formation. This was surprising in that the Hauser reservoir is being waterflooded and the reservoir pressure is higher in the Hauser. With over two decades of water injection in the Hauser, all mobile oil around both OS-2 and OS-3 has apparently been swept and produced. The current oil production from the Ogden in OS-2 is probably related to stopping offset water injection in the Ogden in 2002, just before OS-2 was shut in. It is now believed that water is channeling through fractures from OS-10 to OS-2 and injected nutrients made their way into the Ogden, stimulating microbial growth and the oil release. The microbial activity was elevated in produced fluid samples from the Ogden, but it is difficult to prove that this activity is the main source of the Ogden oil.

Hall Plots and derivative Hall Plots of the three injectors indicate that transmissibility has changed over time (Ozgec, B. 2009). See Hall Plots and Derivative Hall Plots, Figures 6 to 8. Wells OS 10 shows a decrease in injectivity for a short time after the first treatment. This is a possible formation of a temporary emulsion. Sometimes an emulsion forms when oil, water and microbes are present; this emulsion tends to plug the higher permeability paths and improve the sweep efficiency of the waterflood. All three injectors show a slight increase in injectivity with the nutrient treatments. These indications of increased injection match the field's increase in produced water from about 2,100 bwpd to 2,500 bwpd during our project.

Additional Producer Treatments

Based on the results of this ISMRA, two producers, BH 15 and OS 8, were treated on April 18 and May 5, 2008, respectively. Each well was treated with an 8-barrel tote of chemical nutrient solution mixed with 100 barrels of injection water. Displacement volume in the BH 15 was 400 barrels (200% of annular volume) and in the OS 8 the displacement volume was 700 barrels (150% of the annular volume). Giving the microbes time to incubate and populate, both wells were shut in for 4 days (Figures 9 and 10).

OS 8

In both cases microbe populations increase, but neither well followed the normal pattern that was seen after treating OS 1 and other producing well applications. In the OS 8 well, the bacteria showed the normal increase in population. However, the microbes did not move as rapidly into the starvation state as usual. The first month of produced fluid samples showed that the microbes were still in the growth stage, because nutrients remained plentiful. After seeing a production increase, additional samples taken on June 10, showed that the bacteria was moving into a starvation stage. This is a delayed transition to the starvation stage as compared to OS 1. Not only did OS 8 see a delayed oil production increase it saw no oil for some time. Initial well tests showed no oil. Oil was not seen until the May 22 well test, 13 days after the well had returned to production. At this time the well had a cumulative production of about 850 barrels, which is about the treatment volume. No oil was seen until the entire treatment volume was recovered. As the microbes began to respond, the well started producing incremental oil. On June 9, it tested 37 BOPD and 28 BWPD, 43% water cut. In September OS 8 tested 33 BOPD and 30 BWPD, 48% water cut. Since the well averaged 29 BOPD and 36 BWPD, 55% water cut before it was treated, it made some incremental oil. See Figure 11, OS 8 Results Summary.

BH 15

On the first day of production after being shut in for four days, the bacteria in BH 15 showed an extraordinary increase in population as expected. On the second day of production bacteria decrease substantially and the high bacteria count did not repeat. A similar varied oil production response was seen. BH 15 saw an early increase in oil production and decrease in water cut followed by a disappointing decline in oil production and increase in water cut back to its base production. See Figure 21, BH 15 Well Test. During the first week, three well tests were taken and BH 15 was averaging 97 BOPD and 105 BWPD, 52% water cut. This initial high production is probably flush production from the well being shut in. Then the BH 15 dipped to 58 BOPD and 80 BWPD, 58% water cut in September 2008. Since the well averaged 70 BOPD and 110 BWPD, 61% water cut, the well did not appear to make any incremental oil for the first few months. This is not surprising since microbes were not significantly stimulated. See Figure 12, BH 15 Results Summary.

Discussion of Results

Based on both biological indicators and production data, the field showed a positive response to nutrient treatments. As of the end of August 2008, adjacent producers appear to be positively affected with a combined current production increase from five wells of over 30 barrels of oil per day—a production increase of as high as 30% over the base rate of the "front-line" of producing wells and an overall production increase of about 6% of total field production.

In general producing well treatments had excellent microbial response, but only the OS 1 showed significant incremental oil response. It appears that the large volume of displacement fluid in treating

OS 8 temporarily hurt production from OS 8. The treatment may have temporarily changed the relative permeability near the well bore. It took about 13 days to recover the treatment water, when first oil was reported on a well test. It took another 18 days before incremental oil was seen on June 9. This relative permeability problem was seen again following a tubing leak repair. The well was down from June 22 to July 15 due to a tubing leak. When the well was returned to production, its first well test on July 20 showed no oil. By August 8 the well returned to making incremental oil when it tested 37 BOPD and 41 BWPD, 53% water cut.

To get a successful MEOR treatment, the four components (oil, water, microbes and nutrients) must make contact. In BH 15, since the microbes did not respond to the injection of nutrients, the nutrients may not have come in contact with the microbes. One possibility is that the nutrient didn't go in the oil zone. Reviewing BH 15, it is noticed that the gas oil ratio, GOR, on this well is much higher than the field average. Below is Table 3 comparing GORs among the key producing wells.

TABLE 3 Gas Oil Ratios

Well	GOR: SCF/STB	Comment
OS 1	550	
OS 3	760	
OS 4	655	
OS 5	1,000	
OS 7	1,700	Structurally second highest producer
OS 8	857	
OS 11	915	
OS 12	400	
OS 13	160	Structurally lowest producer
BH 15	1,700	Structurally highest producer

It is possible a secondary gas cap formed and the nutrients were injected into the gas cap. Another possibility is that the nutrients were injected into one zone and the well produces predominantly from another. There is no way to know where the nutrients are injected with multiple intervals open.

CONCLUSIONS

The nutrient application targeting specific microbes was proven for this field in the successful application at OS 1. There is no doubt that the production response was a direct result of the nutrient stimulation. Similar nutrient treatments in the three injectors proved that microbes were stimulated throughout the reservoir, releasing incremental oil to the front line producers. Mixed or at least delayed results in the other producing wells, OS 8 and BH 15, indicate that large displacement volumes and secondary gas caps should be avoided.

ACKNOWLEDGEMENTS

Venoco, Inc. for allowing publication. Beverly Hills operations personnel who worked together for a successful application. Peter Spangelo, Venoco, Inc., for preparing the base line data for the full field application. Dr. Jonathan Kwan, Titan Oil Recovery, Inc., for Hall plot derivatives work.

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Figure 1. Beverly Hills Field Production History.

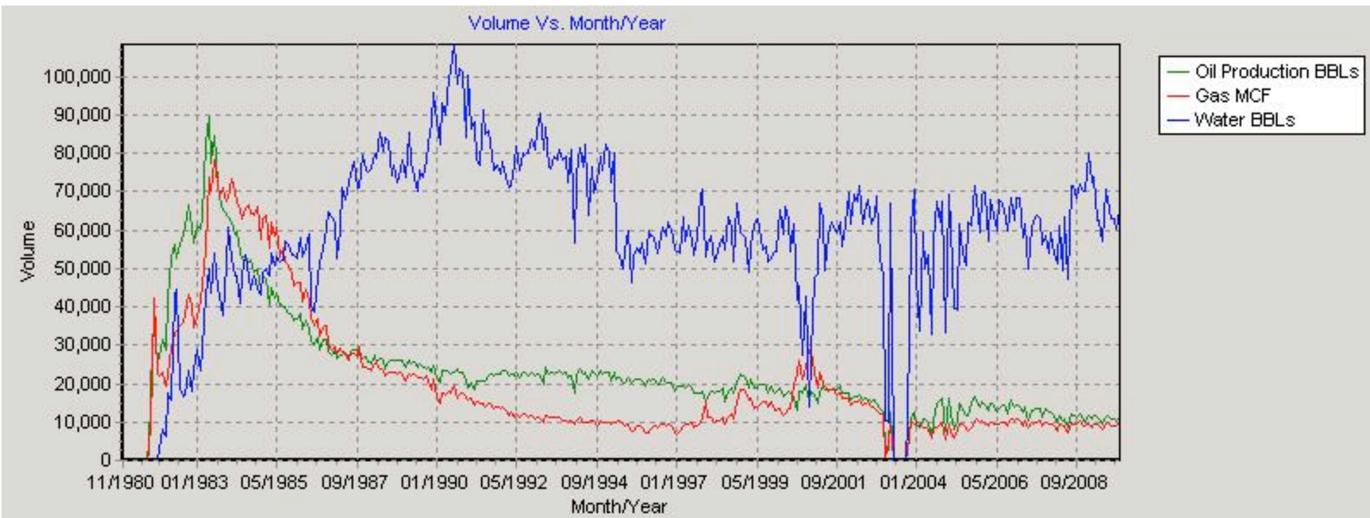


Figure 2. Beverly Hills Field Injection History.

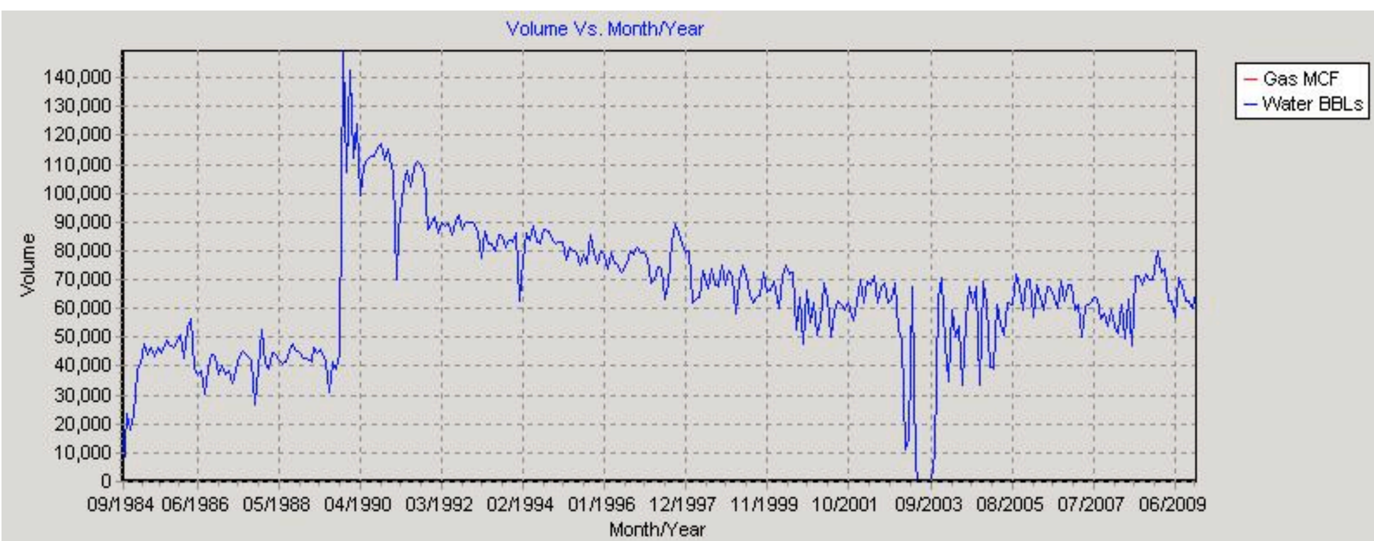


Figure 3. Field Map

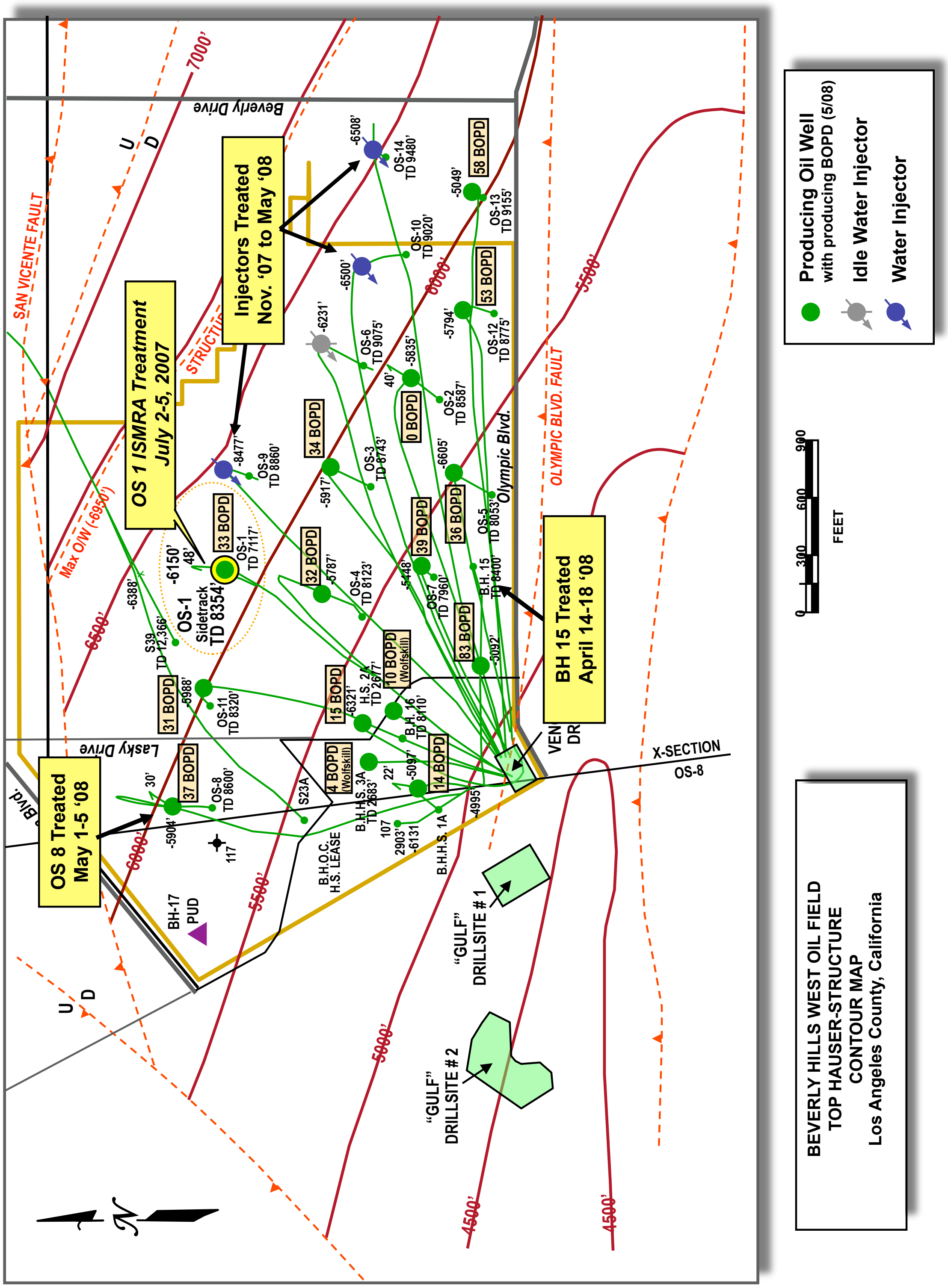


Figure 4. In Situ Microbial Response Analysis, OS 1 Well Test Results

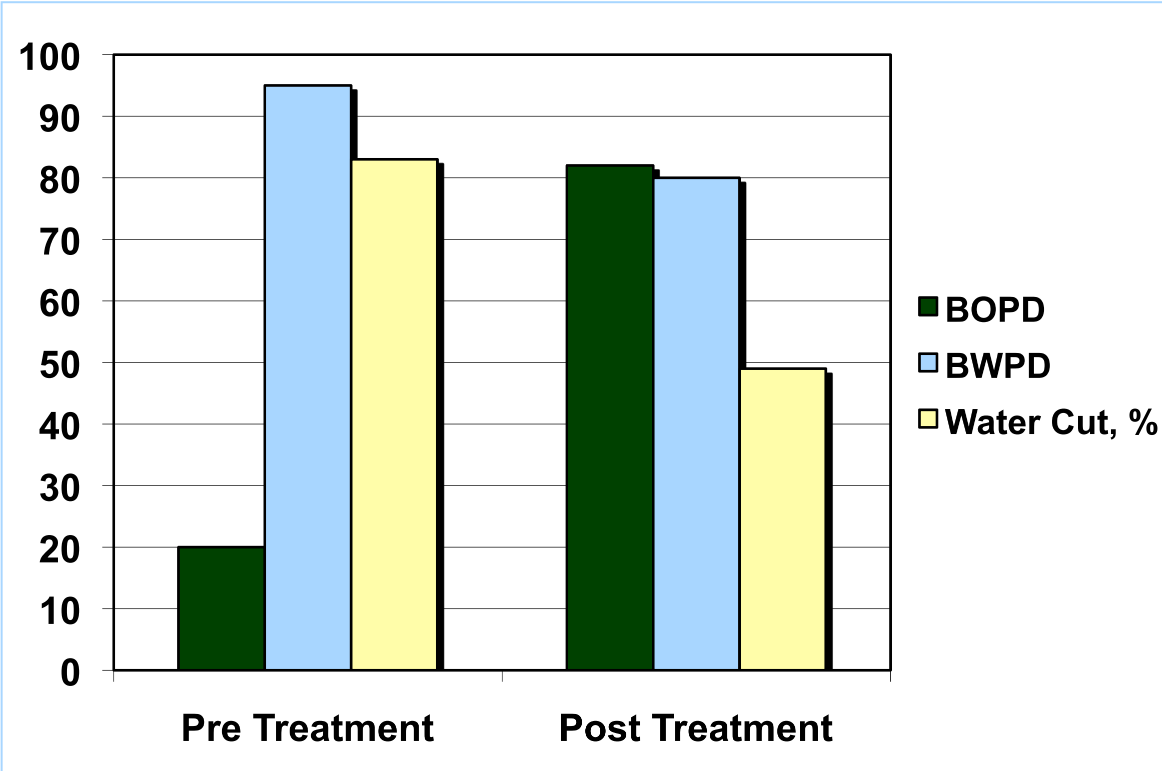


Figure 5. Well Test vs. Baseline, Front line Producers

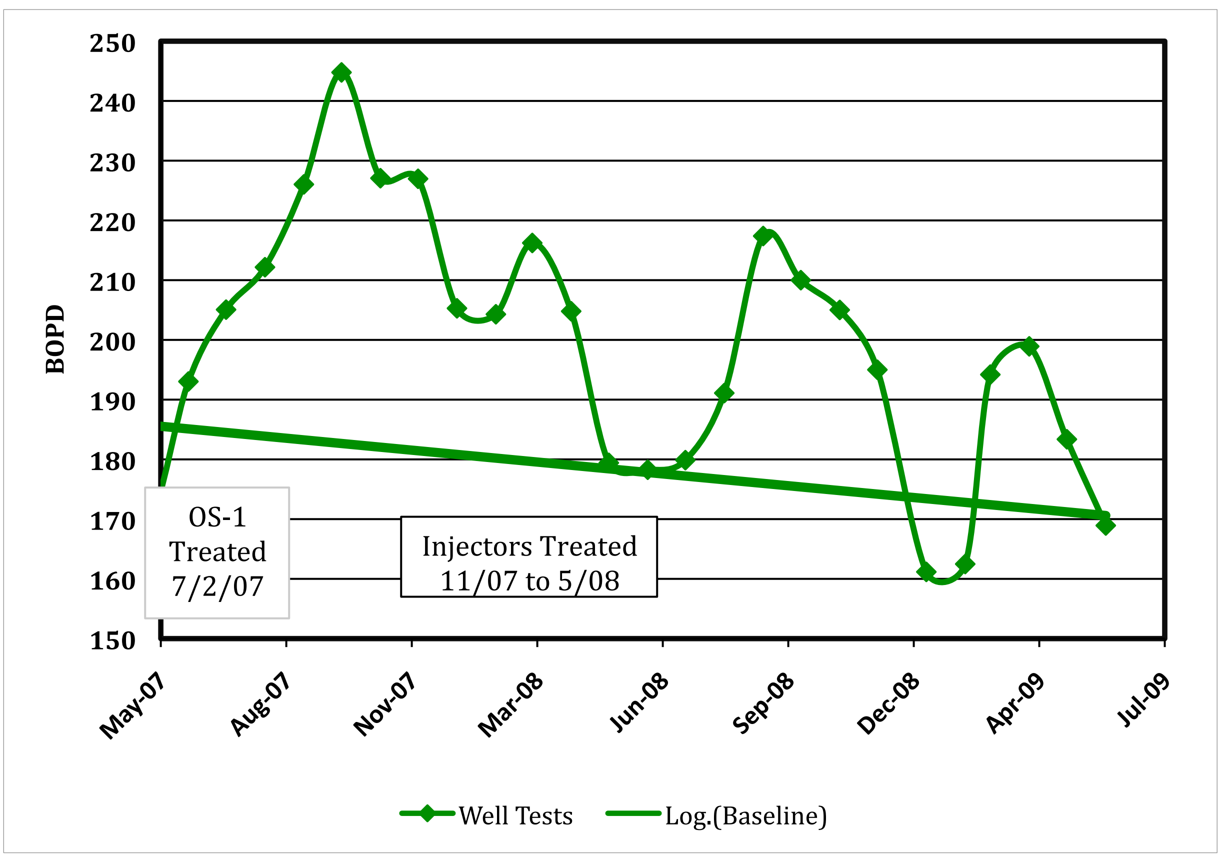


Figure 6. OS 10 Hall Plots

Hall Plots and Derivatives
OS-10 Treatments

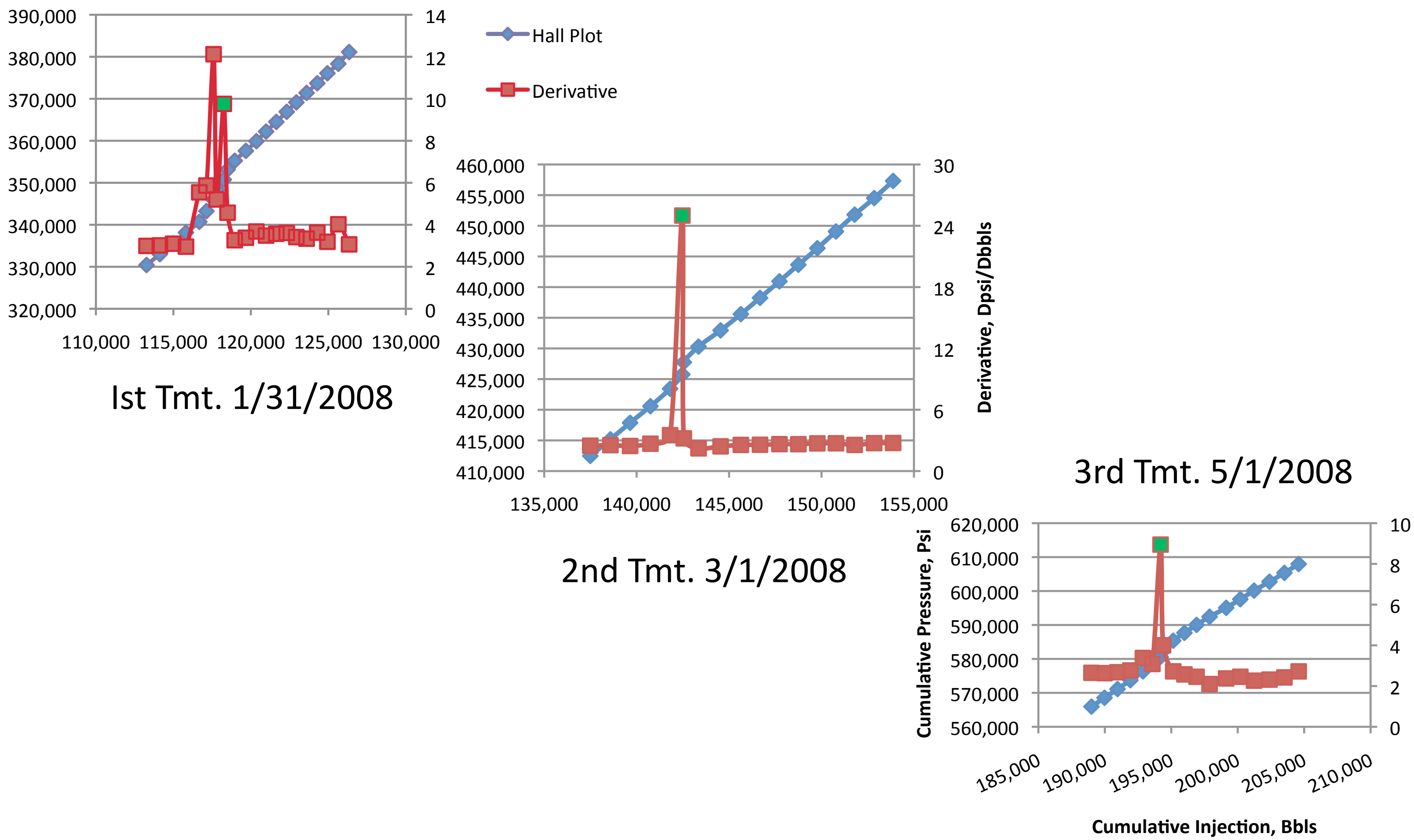
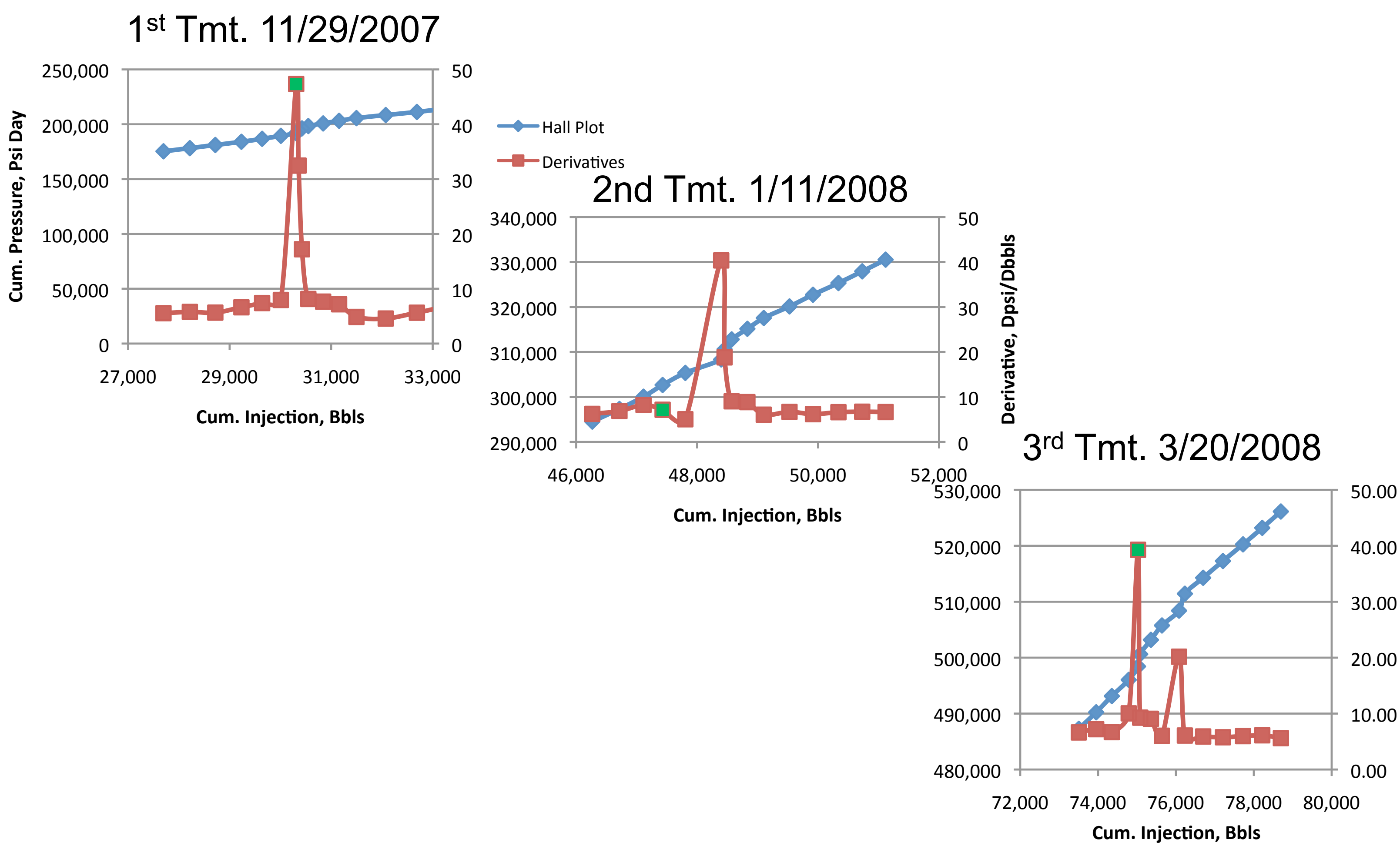


Figure 7. OS 9 Hall Plots

Hall Plots and Derivatives
OS-9 Treatments



Hall Plots and Derivatives
OS-14 Treatments

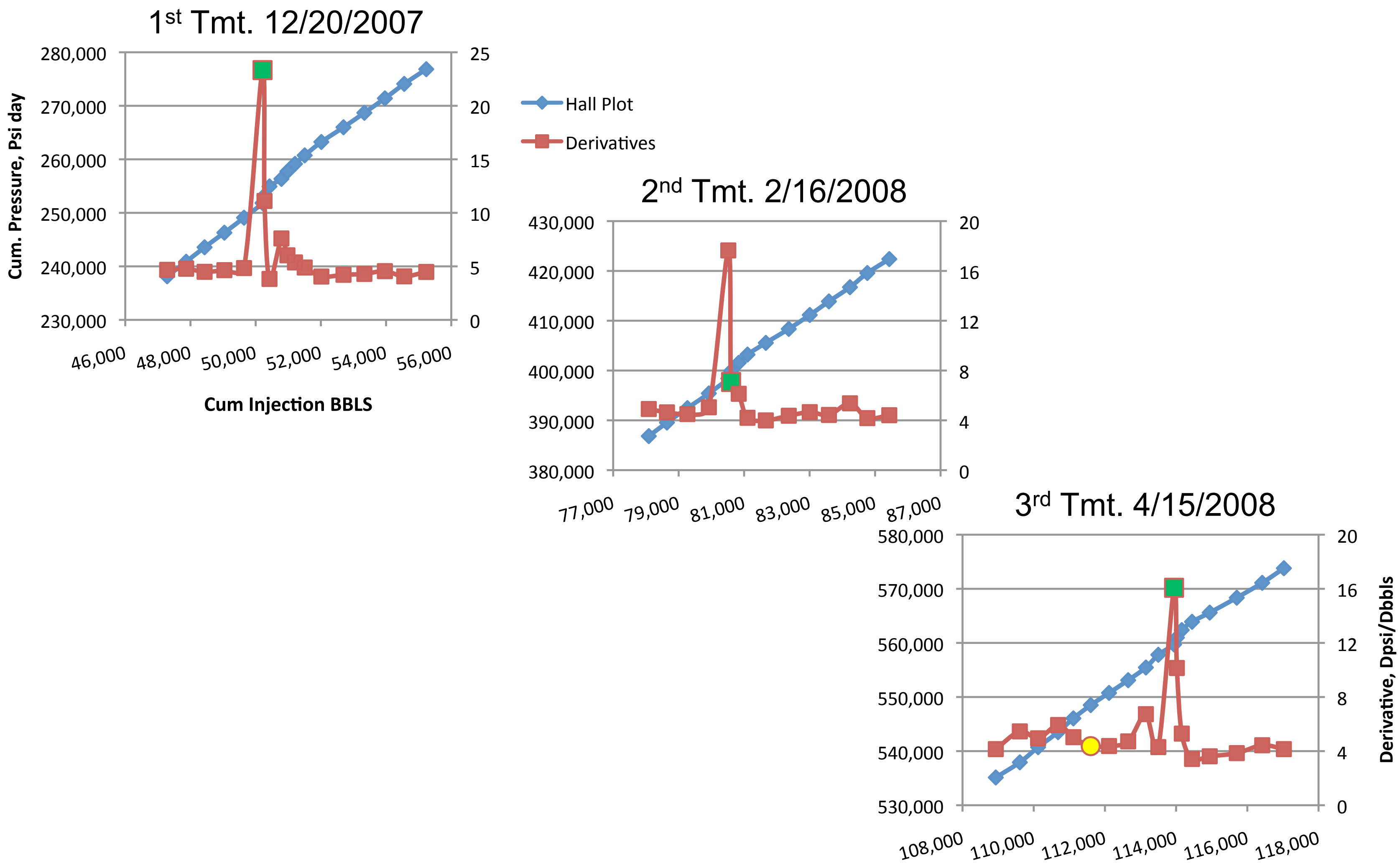


Figure 8. OS 14 Hall Plots

Figure 9. OS 8 Well Tests

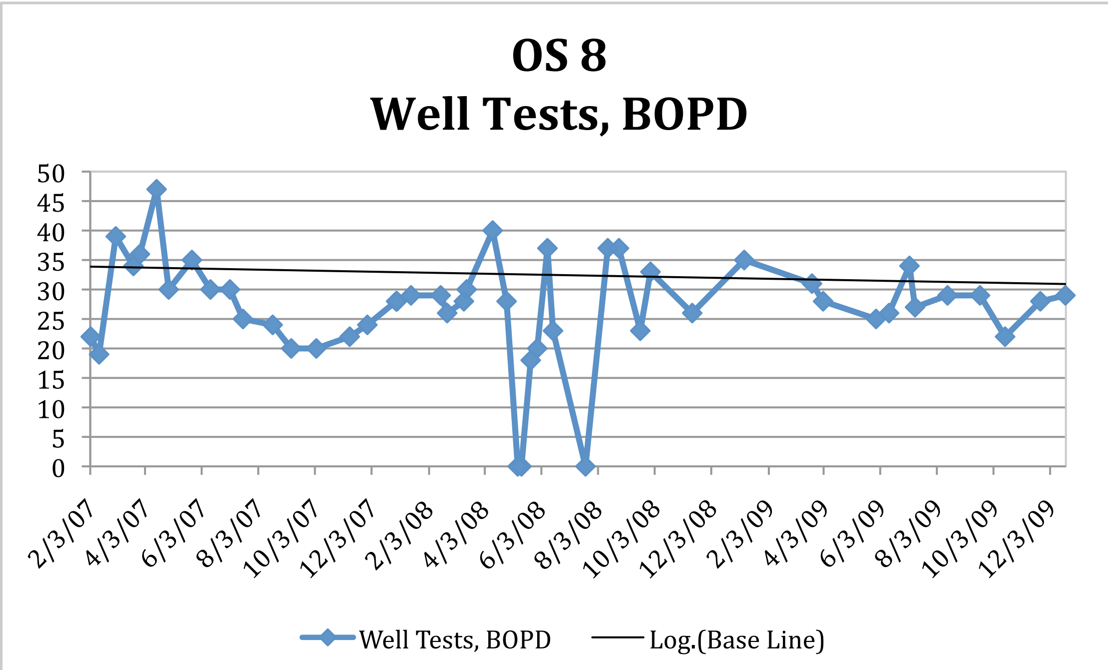


Figure 10. BH 15 Well Tests

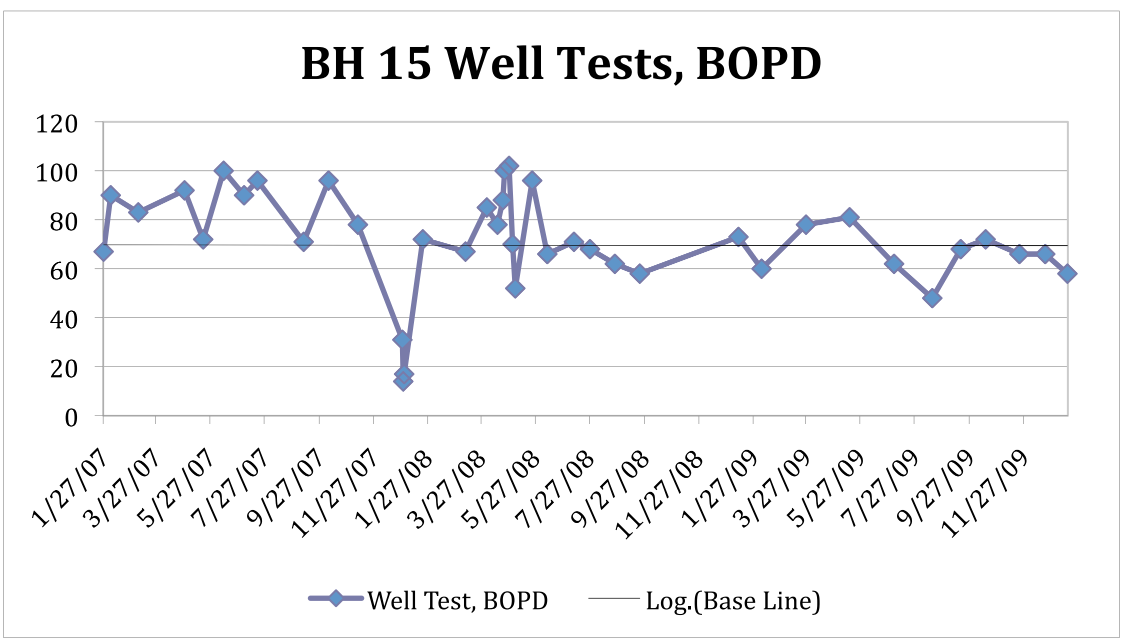


Figure 11.

OS 8
Results

Well Tests before Treatment
(Pretreatment well production)

Date	BOPD	BWPD	%WC
11/28/07	24	44	65%
12/29/07	28	32	53%
12/30/07	28	32	53%
1/14/08	29	43	60%
2/15/08	29	28	49%
2/22/08	26	35	57%
3/11/08	28	30	52%
3/14/08	30	30	50%
4/11/08	40	26	39%
4/26/08	28	29	51%

Feb.–Apr. Weighted Average:	**29**	**36**	**55%**

Well Tests after Treatment

Date	BOPD	BWPD	%WC
5/8/08	0	63	100%
5/12/08	0	66	100%
5/22/08	18	50	74%
5/29/08	20	68	77%
6/9/08	37	28	43%
6/15/08	23	45	66%
7/20/08	0	74	100%
8/13/08	37	41	53%
8/25/08	37	40	52%
9/17/08	23	41	64%
9/28/08	33	30	48%

Tubing Leak 6/22 – 7/16

Weighted Avg. since leak:	**22**	**54**	**70%**
Weighed Avg. since 8/13:	**33**	**38**	**53%**

Figure 12

BH 15
Well Test Data

Well Tests before Treatment
(Pretreatment well production)

Cylinder change: Jan 21.
Scale clean out: Feb. 20-25

Date	BOPD	BWPD	%WC
12/29/07	31	23	43%
12/30/07	14	46	77%
12/31/07	17	19	53%
1/21/08	72	108	60%
3/9/08	67	113	63%
4/2/08	85	138	62%
4/14/08	78	98	56%

Feb.-Mar. Weighted Avg: 70 110 61%

Well Tests after Treatment

Date	BOPD	BWPD	%WC
4/20/08	88	116	57%
4/22/08	100	106	51%
4/27/08	102	93	48%
5/1/08	70	142	67%
5/4/08	52	157	75%
5/23/08	96	85	47%
6/9/08	66	87	57%
7/9/08	71	105	60%
7/27/08	68	95	58%
8/24/08	62	92	60%
9/21/08	58	80	58%

May-Jul. Weighted Avg: 74 106 59%