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Sulphate rejection membranes as an HSE anti-souring barrier in the Ursa-Princess waterflood

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When seawater is injected into a reservoir, sulphate reducing bacteria in the seawater will likely generate H_2S. The processes that influence the extent of H_2S generation, and its transport through the reservoir are complex. When reservoir souring occurs, special operating procedures and safeguards are required to prevent corrosion and stress corrosion cracking of the wells and topsides facilities, and to prevent human exposure and health impacts, and to meet sales gas specifications. While seawater waterfloods have significant economic and reservoir recovery benefits, they demand stringent operational HSE controls. Failure to manage the threat of souring could result in the need to stop production from specific wells, or indeed from an entire field.

While evaluating the effectiveness of seawater flooding in the Ursa-Princess field, it was confirmed that the existing producing wells are sensitive to failure from sulphide stress cracking (SSC). For the waterflood project to gain approval, a robust reservoir souring control strategy was required.

Field Overview

The Ursa and Princess fields encompass 8 offshore continental shelf (OCS) blocks surrounding the Ursa Tension Leg Platform (TLP) in Mississippi Canyon block 809 (*Figure 1*). The Ursa TLP is located approximately 150 miles (240 km) southeast of New Orleans, Louisiana in 3,900 feet (1,182 m) of water. Shell Exploration and Production Company, Inc. (SEPCo) has a 45% working interest in Ursa and Princess and is the operator. The remaining working interest is split between BP (23%), ConocoPhilips (16%) and ExxonMobil (16%).

The structural setting of the Mars / Ursa basin is dominated by salt; the entire basin is a Miocene to Pliocene salt minibasin. The Ursa field is situated in an elongated, ‘open’ basin delineated by the Antares salt body to the northeast and the Venus salt to the west. A deeply rooted, pressure sealing fault system provides the trap component in the south. Ursa and Princess are in pressure communication with each other. Princess is partially located sub-salt to the north of the basin.

The basin fill sediments consist of highly unconsolidated turbidite sands, both sheets and channel type, that were deposited from north to south. Several sediment entry points are known and they are located mainly in the King and Princess areas. A very thick section of pay sands has been proven; hydrocarbons occur in 12 horizons from 12,400 to 19,600 feet (3,758 to 5,940 m) subsea. The base of the hydrocarbons has not been penetrated to date. The hydrocarbon in place volumes for Ursa and Princess are thought to be close to 2 billion barrels of oil equivalent, with about 1.1 billion barrels in the Lower Yellow reservoir alone.

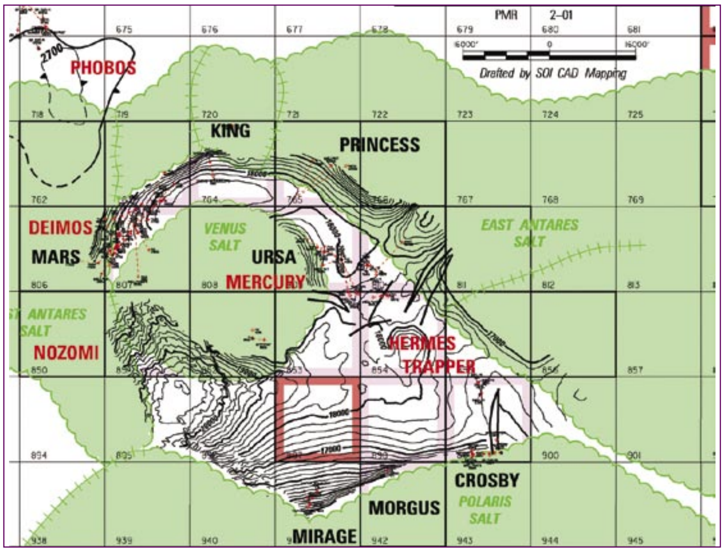

Figure 1: Greater Ursa/Mars basin.

Total production from the Ursa TLP (including Princess and Crosby) peaked at close to 150,000 bopd in the 2002-2004 period. Pre-Katrina daily production averaged 120,000 bopd and it is expected to decline steadily. Future developments (Princess Stage 2, TLP wells redevelopment) and especially the Ursa/Princess Lower Yellow waterflood will all contribute to “fill the gap” in the production profile over the next few years.

The Ursa-Princess Waterflood

The Yellow reservoir does not have a strong natural aquifer support. The mechanisms for primary recovery are mainly fluid expansion and reservoir compaction, resulting in fairly low recovery efficiency of around 30 %. The reservoir pressure has dropped from an initial pressure of 11,800 psi (814 bar) to close to the bubble point at 5,500 psi 379 bar). A waterflood is being planned and is expected to restore pressure in the field and increase recovery efficiencies by another 18 %, resulting in an extension of the field life of approximately 10 years. The initial injection strategy is to provide injection volumes above voidage replacement in order to restore reservoir pressure to bubble point. Thereafter, the target injection volumes reduce with time somewhat as the objective then becomes primarily voidage replacement.

The Yellow sand has the highest field-wide consistency in net pay of approximately 110 feet (33 m) true vertical and good permeability of 250 mD on average. Moreover, oil to water mobility ratio is close to unity, allowing for efficient oil displacement. Production for the Ursa / Princess waterflood (UPWF) would come from a total of 10 wells (*Figure 2*). A total of seven direct vertical access (DVA) wellbores on the Ursa TLP would be utilized as Lower Yellow producers in the waterflood. These wells are a combination of wells already in the Lower Yellow (UA6, UA7 and UA8), wells that need to be recompleted to the Lower Yellow (UA5, UA9 and potentially UA3), and a well that has recently been sidetracked to the Lower Yellow (UA4). The three Princess phase one wells (P2, P3, P4) will remain subsea producers from the Lower Yellow. A new well (P6) is currently being chartered to replace the impaired P4 well.

Current waterflood plans call for four subsea seawater injection wells. Of the four subsea wells, one will be in MC765 and two in the new UAI site and one in MC810. The MC765-1 Princess exploration wellbore will be sidetracked for the subsea well in Block MC765, the MC810-3 Ursa appraisal wellbore will be sidetracked for one of the subsea wells in Block MC810, and the remaining subsea injectors will be new wells.

The UPWF topsides injection system will inject seawater into the Lower Yellow formation via

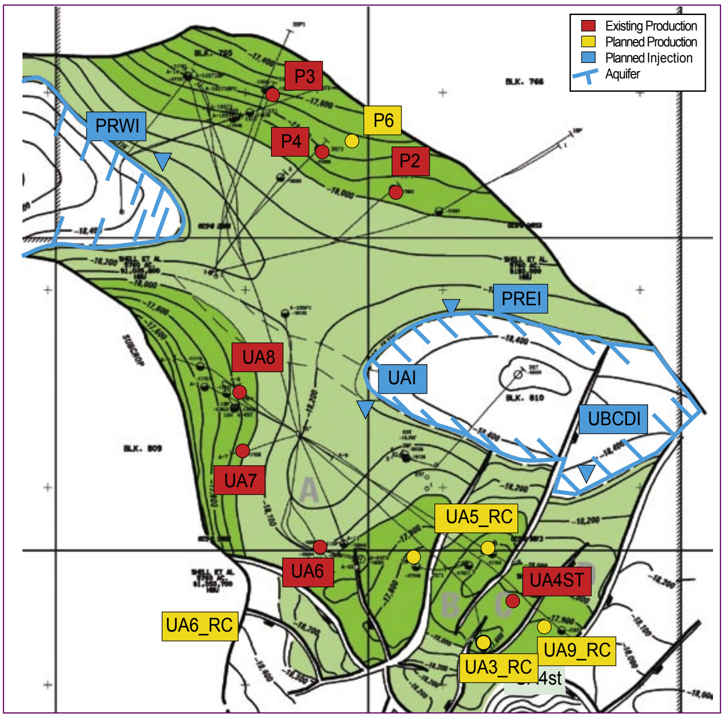

Figure 2: UPWF Well Planning.

two separate flowlines to the 3 subsea sites. The Western flowline will provide water to the existing MC765-1 well site approximately 2.5 miles (4 km) NW of Ursa, and the Eastern flowline to the new UAI wellsite 1 mile ENE of Ursa and subsequently to the existing MC810-3 well site just 1/2 mile to the SE of UAI.

The UPWF injection system will be designed to deliver an annual average flow rate of 130,000 BWPD at 7,500 psig 517 barg). First injection is estimated in Q3 2008. Based on the latest simulation results, the expected discounted total gross incrementally recoverable sales volumes for the UPWF Project is estimated to be 207 mln BOE. With the addition of the P6 replacement well, this number increases to 227 mln BOE.

Development of an Anti-Souring Strategy

Due to the many variables that influence the generation, absorption, partitioning and transport of H_2S, model predictions carry high uncertainty unless calibrated against laboratory and field data. The waterflood research team in Rijswijk, therefore, performs laboratory experiments under well characterized and controlled conditions to develop an improved understanding of souring mechanisms. In addition, Shell is also actively involved in a multidisciplinary industry-wide collaboration to share reservoir souring field experience. The combination of both activities has resulted in a reasonably coherent picture of the processes that influence reservoir souring. As a result, a few anti-souring strategies are now gaining wider implementation.

The first of these strategies is to use THPS, a unique biocide, in batch doses at high concentration, and over relatively large injection volumes. Continuous THPS injection would probably be even more effective, however it would be extremely cost prohibitive. High dose batch treatment has proven effective in at least three fields as a means to reduce resident reservoir souring, once it has already occurred. However, the current industry consensus is that THPS application in this fashion has yet to demonstrate a proven effectiveness for prevention of souring in the reservoir.

The second strategy is to dose the injection water with nitrate, a bionutrient which, among other things, promotes the growth of nitrate reducing bacteria. The nitrate reducing bacteria compete with sulphate reducing bacteria, which are responsible for souring, in a process referred to as biocompetitive exclusion. The preferred strategy is to inject nitrate from day-one of the waterflood. This approach is being applied for the Halfdan (operated by Maersk), Horn Mountain (operated by BP), Mars, Bonga and Barton fields. This strategy is still considered to be relatively unproven because to date, only a few years of experience have been attained. However in those fields where seawater has broken through to the producing wells (BP Horn Mountain, Maersk Half-Dan), no H_2S has been seen as a result of the seawater waterflood. In other fields, where souring was already present, and nitrate has been added after the fact, the results have been difficult to interpret. Overall though, indications are that nitrate injection is effective.

The third strategy to control souring is the use of sulphate removal (rejection may be a better word) membranes (SRM). Seawater contains a high level of sulphate which creates two problems, reservoir souring and formation of barium sulphate and strontium sulphate scale (collectively referred to as sulphate scales). SRM were originally implemented by Marathon Oil Company in 1989 to prevent sulphate scaling. Since sulphate is also the ultimate source of H_2S in reservoir souring, the potential use of membranes for controlling H_2S was recognized almost immediately. However,

Figure 3: Jimmy Leeper (left) and Anthony D'Amico (right, both from SEPCo Operations Readiness and Assurance Team for the Ursa-Princess Waterflood) standing next to the sulphate membrane skid during an inspection visit to the vendor fabrication yard, February 2007.

problems with the mechanical reliability of the membrane systems, and the question of how much sulphate must be removed to prevent souring had to be resolved before the industry could accept SRM as a souring control strategy.

In 2004, a project team was formed to gather laboratory and industry field data to evaluate the suitability of the three souring control strategies for the Ursa-Princess waterflood, and to prove or disprove the reliability and effectiveness of sulphate membranes. Regarding reliability, we learned that implementing a sulphate membrane unit is technically challenging. We also learned that proper seawater pre-filtration is critical. In general, seawater contains small particles which must be removed by a pre-filtration stage to prevent fouling of the sulphate membranes. A fraction of the small particles come from silt from terrestrial runoff, and the remaining fraction comes from natural biogenic processes occurring in the ocean surface waters. The precise type of filtration required depends on the characteristics of the seawater in the particular location. To address the pre-filtration needs, the Ursa operations personnel carried out an extensive on-site filtration study at the platform.

To understand reliability, we contacted all of the major operators of sulphate units to obtain their lessons learned and we visited one of the recently installed SRM units in the North Sea (the Heidrun TLP). We found that the reliability of these systems has improved dramatically but in those locations where weight and space limitations require design compromises, then there remains a significant risk of poor performance. Working with an EPT-P team, we confirmed that it would be feasible to install and operate a reliable system on the Ursa platform.

Field data were obtained from roughly a dozen operators which showed that no waterflood using sulphate rejection membranes has soured. At least a few of these fields have experienced five or more years of seawater breakthrough and have experienced several pore volumes of seawater injection. In addition, the team carried out laboratory experiments and computer simulations which showed that the Ursa-Princess reservoir has significant capacity to scavenge H_2S, should small amounts be generated in the reservoir even with the use of SRM. Using the Shell Hazards and Effects Management Process (HEMP), the SRM was proposed as an anti-souring barrier. Leadership endorsed this strategy, provided that each well contain at least one additional Shell H_2S-qualified pressure containment barrier (i.e. completions or casing), and that a rigorous H_2S monitoring strategy be implemented for each producing flow line at the start of waterflood.

Conclusion

SRMs were selected by the Ursa Development Team to minimize the likelihood of souring the Ursa Princess reservoirs during seawater flooding, and to reduce the risk of barium sulphate scaling at the producer wells. This does not mean that a justification now exists for the selection of highly intolerant H_2S well materials for future projects. It does, however, mean that SRM technology will be implemented by Shell, for the first time in the industry for the dual purposes of souring prevention and scale mitigation. The UPWF is scheduled to go on-line in 2008. For more information, contact any of the authors or the Waterflood T&OE Team (Niel O'Neill, David Mabbitt, Dave Chappell).

Comments from Rob Eylander, PTE Water Management / IOR / EOR

Worldwide, more than 70% of seawater flooded reservoirs have turned sour. The awareness that a complex combination of factors such as seawater de-oxygenation, the introduction of both sulphate reducing bacteria (abundantly present in seawater, albeit in a "dormant" state; these bacteria only become active in an anaerobic environment) and an essential growth nutrient (sulphate, also abundantly present in seawater), as well as the presence of other essential bacterial activity contributing factors in the near wellbore area of injection wells, became apparent in the 1980s. Since then, extensive research and in-depth reviews / sharing of operational experiences have yielded an industry-shared wealth of insight and understanding of microbiological activity in and resulting souring of seawater-flooded reservoirs. The authors of this excellent EPJT contribution point out that despite all of this, significant areas of uncertainty remain that impact on CAPEX decisions and lifecycle OPEX expenditures. In this article, the authors and their contributing team members, share how they have addressed and developed effective and business-justified control measures of these uncertainties. The application of state-of-the-art membrane technology to decrease sulphate levels in the injection water is an example, but also the team's realization that "state-of-the-art" remains to date insufficient (i.e. sulphate levels are not reduced to the extent that it entirely excludes the possibility of bacterial activity, based on current insights), that it needs to be augmented with additional measures (viz. batch biocide injection), and that more research is required to develop fully adequate and cost-effective control measures. Although some uncertainties remain attached to this technology in terms of controlling microbiological activity, the probability that it will in the medium term contribute to obviating the need for very expensive scale squeeze treatments in the producing wells of seawater flooded reservoirs is very high, yielding tens of millions US$ savings / annum.

Did you note the manner in which this team capitalized on global networking, internally and externally, and its contribution to the business? I hope so, because it convinces me that it differentiates us from our competitors and makes us the partners of choice.

John joined Shell in 1991 and worked at Westhollow as a physical property and flow assurance expert for roughly 10 years. In 2001, he joined SEPCo as the chemical engineer for the Mars TLP. John was the team lead for this project. He is very grateful to all the other team members for their outstanding work, and to Dorine (development manager) for supporting the work at every stage.

John Walsh

Robert is a consultant working for RISKBytes inc. He graduated from Imperial College in 1984 with a degree in civil engineering. He initially worked as a structural engineer before joining the ocean engineering research staff at Glasgow University and gained a PhD. He then became a consultant on major projects like Shell's Brent Redevelopment. In 2000 he joined SEPCOs HSE team in New Orleans where he supported HSE Case development on projects like Mars and Ursa waterflood.

Robert Prince-Wright

Cor completed HTS chemistry study in Rotterdam. After 12 years in the Rijswijk laboratory in various production chemistry related projects, Cor worked as a process production chemist in PDO and NAM. Cor returned to Rijswijk in 2003 and has been working in Water Management projects, including water treatment and reservoir souring topics.

Cor Kuijvenhoven

David Ramsey joined Shell in 1984 working in Bakersfield, California. He transferred to New Orleans for the Ursa Project in 1996. In 2005, he joined the Operational Readiness Team for a year and a half as the focal point for the Ursa-Princess Waterflood Project where he participated in the Sulphate Reduction Study Team.

David Ramsey

Charles joined Shell in 2002 as a process engineer. Charles was a member of the EPT-P group in New Orleans and as such he provided an important link to the project community. and was the lead process engineer for UP Waterflood from 2005 to the end of 2006.

Charles Deuel

Frans joined Shell in 2001, after a 13 year career in applied geoscience R&D. His first role at Shell was in the development and global rollout of the Volumetrics tools FASTRACK and XTRAP. Then he joined the newly formed IRM Global Implementation Team. In 2005 Frans joined SepCo / EPW as staff reservoir engineer for the Ursa/Princess/Crosby asset and has been subsurface lead for the UP Waterflood since mid 2006.

Frans Floris

Dorine joined Shell in 1993 and has worked in field development and economic roles in Aberdeen, New Orleans and Perth. Dorine recently finalised her assignment as the commercial manager for the Gorgon field, and is now the technical services manager for Shell Australia. Dorine was the development manager for the Ursa field.

Dorine Bosman