Abstract

The Polymer Injection Project on Dalia field, one of the main fields of Block 17 in deep offshore Angola, is a world first for both surface and subsurface aspects. Thorough geosciences and architecture integrated studies led to decide to phase the project, with a polymer injectivity test on one single well, followed by a continuous injection of polymer on one of the four subsea lines delivering water to the field.

The single well injectivity test on DAL-710 was completed first quarter of 2009, just two years after first oil. Very successful results led to launch a polymer injection pilot on the full injection line of the Camelia reservoir.

The main objectives of the single line Camelia pilot were to confirm long term operability and injectivity of polymer in the specific conditions of this deep-offshore development, and measure the in situ viscosity (sampler well) of the injected polymer solution away from the injector, as key inputs to the evaluation of an extended project.

From February 2010 to August 2012, a 900 ppm polymer solution was injected through the three wells of the line. In summer 2012, a sampler well was drilled 80 m far from one of the injector, located behind the polymer front thanks to 4D seismic monitoring. MDT and bottom hole samples were done and analyzed.

The paper describes the main results of the pilot phase on injectivity, operability and polymer sampling. The pilot answered its objectives, but still a lower viscosity than expected was measured in the sampler well. Key deliverables were:

- How to operate the whole process chain of viscosified water at topsides level
- Better knowledge of polymer degradation from topside to deep into the reservoir
- Data required to properly size an extended polymer project.

Introduction

Located 130km far from the coast, the Dalia field is a major deep offshore development in Angola, and is part of the Block 17 (Figure 1) success story of Total - operator- together with the Concessionnaire and Partners, starting with Girassol in 2001, Dalia in 2006, PAZFLOR in 2011, and lately CLOV in June 2014.
A subsea development scheme with water injection for full pressure maintenance was decided together with gas reinjection waiting for Angola LNG export. Very early in the geosciences studies, oil viscosity was identified as the main limiting factor to the water injection recovery. Considering the key parameters of the reservoir: medium viscosity, low temperature, high permeability sandstones, polymer injection was positively screened as a potential EOR method for the Dalia Field.

Extensive integrated architecture and geosciences feasibility studies of polymer flooding started in 2003, three years before production start-up. Many challenges needed to be addressed as no EOR or polymer project had ever been implemented in deep offshore conditions. A phased approach was decided in order to assess and reduce the main uncertainties of the project, consisting in the construction of a powder polymer solution preparation skid, a single well injectivity test, a longer injection period through one of the injection line (supplying three wells) and the drilling of a sampler/producer well in order to assess in situ viscosity, while continuing the surface and subsurface studies.

**Dalia Reservoir and Development Key Data**

The Dalia field is a group of four turbiditic complexes from Lower Miocene to Middle Miocene ages, called Lower Main Channel, Upper Main Channel, Lower Flanks and Camelia (Figure 2). The field stretches over 230km², by an average of 1300m water depth.
The very high quality of the 3D - and 4D- seismic data has allowed direct mapping of the main architectural reservoir elements, like sands and clay areas only 6 to 10 meters thick. The channel complexes can be as thick as 100 meters, but are divided and subdivided in different heterogeneous sections with alternating layers of oil sands and clays, piled in complex geometries.

The field permeability ranges from a few hundreds of milliDarcies to several Darcies, with an average permeability above 1 Darcy.

The relative shallowness, around 800m below sea bed, explains partly the quality of the oil 21 to 23° API.

The oil characteristics are:

- Specific gravity: 0.920 (12-23°API)
- Viscosity: 1 to 10cP @50°C
- TAN: 1.5
- Reservoir pressure 215 - 235 bars
- GOR: 70m3/m3=400scf/bbl
- Associated gas: 4 to 7% CO2
- Formation water salinity:110-120g/l – some barium

The field is developed by water injection, using an FPSO with 28 deviated or horizontal subsea injector wells and 4 injection flow lines (plus 3 gas re-injection wells active before Angola LNG start-up). A single flow line generally injects in several reservoirs as well as several systems. Maximum yearly average water injection is 360 kbwpd. Desulfated sea water is injected since start-up, in order to prevent any barium sulfate deposition and all the produced water is reinjected.

Production is achieved through 4 production lines and 40 producers. First oil was on 13th December 2006. The 240 kbpd oil production plateau was reached after a few months while now, 8 years after start-up, the field is still producing at a “reduced” plateau rate of 200 kbopd. More details on the field development can be found in Picard (2007) and Caïé (2007). A schematic of the layout is given in Figure 3.
Dalia Polymer Project

Feasibility studies
Polymer feasibility studies on Dalia, integrating geosciences and surface facilities teams, started as early as December 2003, meaning just after the development sanction of the project and 3 years before first oil. The key findings of these studies are briefly recalled hereafter, and more details are to be found in Morel et al (2008):

- A high molecular weight hydrolysed polyacrylamide has been proven effective to viscosify the water under the salinity, temperature and high permeability clean sandstones conditions prevailing in the Dalia field
- Powder supply has been retained, being feasible and more cost effective, including logistics issues
- Positive stakes have always been observed during simulation studies provided sufficient injectivity is achieved

After these promising preliminary results, more detailed studies were launched to further define the injection strategy (concentration- slug size- timing), and decide on the derisking/ pilot strategy while base line response to water injection only was not yet available.

Assessing polymer flood efficiency - Polymer Response
Among the key performance parameters of Dalia polymer injection implementation, assessing the efficiency of polymer flood in situ was a major one, for the sake of taking the appropriate and timely decision regarding its full field deployment.

The favorable reservoir characteristics of Dalia turbidites sandstones, in this deep offshore environment, helped define an optimized well pattern, as described hereabove, with a reduced number of wells, and thus a large spacing between injectors and producers (from 1000 m to 1500 m).

As a consequence, the production response to polymer injection is slow: the water cut decrease (or slowing down of the water cut increase), or even the polymer breakthrough was expected to take from 3 to 5 years (Figure 4) based on simulation work. In addition, the magnitude of the water cut decrease was hard to detect on the short term as several producers flow through a commingle production line.
Different options were considered to demonstrate polymer efficiency in a shorter time than 3 to 4 years after the pilot phase 1 starts, and move ahead the sanction of the extension by one to two years.

Among the various options studied, saturation monitoring in an infill observation well, trying to visualize the displacement of an oil bank mobilized by the viscous solution has been thoroughly evaluated. This monitoring way was discarded because the uncertainty on the measurement was within the range of expected changes. The drilling of an infill well, a producer, an injector or an observation/sampler well, was considered. A thorough evaluation of pros and cons of each option was carried out including feasibility, value of information and economics.

Eventually, it was proposed to drill an infill sampler well close to a viscosified water injector in the pilot area, with an additional production target in a deeper horizon. The objective was to sample viscosified water in this well, and to check whether the in-situ properties of the polymer solution were consistent with retained hypotheses, under the salinity and concentration conditions of the sample. The main objectives of this sampler well were twofold:

- Sample the viscosified water in top layer swept by viscosified water,
- Produce undeveloped bottom layers.

Polymer flooding being a proven EOR technique in high permeable sandstones onshore, it is assumed that provided the in-situ viscosity of the polymer is in line with the retained design, after passing through the whole set of injection facilities specific to deep offshore implementation, incremental recovery should be as expected.

**Derisking strategy**

A phasing of the project was therefore sanctioned in order to address the main risks of injectivity and efficient preparation of polymer solution offshore, and be in a position to better assess the corresponding stakes. The following steps were defined:

- Single well injectivity test with the double objective to demonstrate that
  - Reservoir voidage replacement can be achieved at the same path with polymer and water only injection, choosing a well with medium water injectivity performance
  - Powder based polymer solution preparation and logistics are achievable offshore on a FPSO under the specific conditions of Angola
- One Full line polymer injection with the following objectives
  - Evaluate longer term injectivity (>1 year) on several wells
○ Further demonstrate feasibility of polymer preparation offshore
○ Measure in-situ viscosity of the polymer

The single injectivity test was achieved from December 2008 to first quarter 2009 on a deviated well from the Camelia reservoir and provided excellent results and the decision was taken to move to the full line injection. More details on the single well injectivity test results and the selection of the full line for longer term injection are to be found in Morel & al (2010).

**Full line polymer injection**

Full line polymer injection officially started on 8 February 2010, with injection on the flow line that exclusively served the Camelia reservoir at that period of time. Polymer injection was stopped in August 2012, after 7 millions cumulative barrels of viscosified water injection had been injected. Polymer concentration was around 900ppm and a maximum of 5 t/day of polymer was injected.

Excellent quality polymer solution has been prepared all through the pilot duration, meeting every specification from QA/QC (mainly O₂ content, filter ratio, insoluble content, viscosity).

Still the skid operability was not ideal, the skid uptime being over 80%, but at the expense of intensive efforts from the operational teams, and the maximum operating rate being 10% below the specifications. Very strong and valuable learnings have been acquired during this pilot phase.

Long term Injectivity has been proven excellent on the horizontal wells.

Injectivity on deviated well was excellent when polymer solution was diluted with desulfated water, but a significant injectivity index decrease was abruptly observed in August 2010 on the deviated well DAL-713 as illustrated in Figure 5, moving from 30-20 to 10 m³/d/bar.

![Figure 5—Evolution of Injectivity Index and Flowing Pressure in DAL713](image)

Different attempts were done in order to restore the injectivity by injecting slugs of desulfated sea water, but the initial injectivity index was never recovered. Still it remained stable afterwards until the end of the polymer injection.

This injectivity index decrease has been attributed to the poor quality of the PWRI (produced water) used at that time to dilute the polymer solution.
**Polymer Sampler**

**Sampler well placement**
The placement and 3D trajectory of the sampler well, as well as the more appropriate timing to drill it, were based on the 4D seismic results, reservoir monitoring and dynamic reservoir simulations which altogether give a good understanding and a detailed view of the reservoirs.

**4D post processing aspects: warping of the monitor data**
Two production mechanisms are present in the reservoir: depletion and water injection. As the initial oil pressure is very close to bubble point, gas exsolution is very quickly associated to depletion. Due to unconsolidated sands and low burial, 4D effects are very large in amplitude and time shifts: amplitude variations can reach 130% and time shifts over 10-15 ms are observed in highly depleted areas.

In the water swept area, the amplitude variation is close to 60% and the velocity change is close to 7%.

These amplitude variations and the 4D time shift are both largely above the repeatability noise of the 4D seismic, which for this acquisition was measured to be at 12%.

In order to optimize the position of the sampler well (i.e. maximize chances of sampling viscosified water), the interpretation was focused on the dVp/Vp attribute. This attribute is computed using an in-house warping tool that realigns the monitor seismic data in time with the base data. Because this timeshift is directly related to local velocity changes it is possible to compute a dVp/Vp volume. The in-house warping algorithm is a direct inversion for relative velocity changes that explain the timeshift and the amplitude variations between base and monitor surveys. As the warping is a data driven inversion approach (without initial model), the dVp/Vp attribute is computed in a very short time.

**Figure 6** shows typical responses of a depleted area around a producer and of a swept area around a water injector. In areas adjacent to producers we observe a depletion of around -10 bars to -40 bars associated with gas coming out of solution and a decrease of P velocity: dVp/Vp negative (red).

Around water injectors, water is replacing oil, which creates an increase of P velocity: dVp/Vp positive.

**4D interpretation to localise the sampling well**
From the dVp/Vp cube it is possible to extract maps for each layer involved in the project of this new well.

It was mandatory to target the top layer in the swept area to sample the viscosified water and to target the bottom layer in the unproduced area expected not to be depleted.

Figure shows the map of a positive dVp/Vp anomaly showing clearly the extension of water injection and the position of the water front. This dVp/Vp map overlays an Architectural Element (AE) map describing the sedimentary body sand extensions.
The sampling well trajectory was designed to intercept the blue area in this top layer and a non anomalic area for the bottom layer, for which we expect that the reservoir has not been produced yet.

The location of the sampler well was selected close to the viscosified water injector to minimize the risk of drilling in an area with no polymer. The high quality of the 4D seismic data acquired mid 2008 and end 2010, was of a great help to identify the water flow paths, layer wise, between the existing injector and a nearby producer as already anticipated based on reservoir monitoring analysis. Dynamic reservoir simulations succeeded in matching 4D anomalies.

Based on these simulations and the concentration evolution forecast, the timing of the well drilling was fine tuned in order to secure the in-situ sampling. A cumulative injected volume of polymer solution was defined. The concentration map (Figure 8) is linked to the volume of polymer injected in the injector well.

Figure 7—The blue area represents the positive $dV_p/V_p$ anomaly corresponding to the water swept area. The AE map shows the sedimentological extensions of channel and levees.
Sampler Well Drilling Operations

Drilling operations started mid 2011. The sampler well was drilled near a viscosified water injector (~80 to 190 m), and located behind the polymer front thanks to 4D seismic monitoring (as seen on Figure - see Hubans (2012) for more details).

Two side tracks had to be drilled because completion could not be run due to clay instabilities. The clear map and section of the swept area (respectively Figure and Figure 9) were very instrumental in designing the side track trajectories.
In summer 2012, the sampler well was eventually completed in Cx13A for water/polymer sampling purposes, and in Cx8 for oil production purposes with 5 ½” Stand Alone Screen of slot 8, including a mechanical sliding sleeve, in order to allow isolation of the upper reservoir (Cx13A) during the production of the bottom reservoirs.

Besides the primary objective of polymer monitoring, and after shutting in the completions in the layers submitted to polymer injection, deeper reservoirs that were not developed yet, and were identified thanks to seismic data, were put on stream with that well.

**Polymer sampling**

An extremely detailed study was undertaken in our laboratories to check that representative samples of the in situ polymer solutions could be taken with existing sampling tools, and that all analytical issues might be solved to measure the key properties of the solution.

While Bottom hole sampling (BHS) after the completion of the well was clearly identified as the preferred and most representative sampling procedure for these particularly delicate operations, a first attempt was carried out to collect samples by means of a modified MDT device (in reverse low shock configuration) in open hole just after the drilling phase of the well (mid 2011).

**MDT sampling**

Polymer sampling with a modular dynamic tester (MDT) tools was tested onshore to check that the polymer solution did not undergo significant mechanical degradation during sampling. The MDT reverse low shock configuration for which, sampled polymer does not pass through the pump, was qualified during these tests.

Another issue with the sampling in a new drilled well is mud contamination. Therefore, MDT was equipped with:

- a quicksilver probe in order to reduce the clean up time and minimize mud filtrate contamination.
- an in-situ fluid analyzer (IFA), with a DV rod and a mini vibrating wire (field tested) to have real
time information on the fluid contamination (water/oil fraction, density) and fluid viscosity in the flow line.

In order to prevent polymer from chemical degradation due to the presence of reduced iron and oxygen, brand new valves and sulfinert coated MDT sampling capacities were used. Before their installation in sampling compartments, several cycles vacuum/ultrapure N2 were performed on dead volumes of sampling capacities so as to remove any trace of oxygen. Brand new sampling capacities were used in order to prevent any trace of rust in the bottles. The complete tool string was tested onshore just before the operation.

During the sampling job, all the precautions were taken in order to recover a clean polymer solution with minimum OBM filtrate and oxygen contamination. Sampling flow rates were carefully controlled to prevent the polymer from mechanical degradation.

The whole part of the samples collected downhole were then transferred in a controlled manner on the RIG floor in sulfinert coated sampling bottles. Pure Helium was used for flushing the transfer line and dead volumes. Transfer flow rate was carefully controlled to prevent any mechanical degradation. The MDT samples were collected at 188 m from the injector well on layers CX12, CX13A and CX13B as seen on Figure 9. One part of the downhole samples taken on the RIG floor was analyzed directly in Dalia FPSO polymer lab. The other part was sent to France. In situ properties (concentration, viscosity and degradation) were evaluated. Should samples be found contaminated (presence of oil, mud, solids...), specific analytical procedures had been set up in order to remedy the situation.

The MDT operations confirmed that the samples were made behind the polymer front meaning that the target was properly selected. The results in terms of viscosity were inconclusive, thus confirming the initial plan to run a BHS tool.

### Bottom-hole sampling

As defined in the working program of Phase 1, a Bottom Hole Sampling was performed, mid 2012, in order to prevent any possibility of mechanical degradation during the sampling.

The objective of the sampling was to measure the actual in-situ properties of the polymer injected from the FPSO after propagation in the reservoir and to conclude on Dalia polymer pilot (Phase 1).

The tool had been previously tested onshore and adapted to polymer sampling. A special visco jet was used in order to limit the flow rate during the suction of the sample and to prevent the polymer from mechanical degradation. Sampling was simulated onshore by working with a fluid at the same pressure than the reservoir. As for the MDT operation, sampling and transfer bottles along with transfer bench lines were carefully flushed with ultrapure gas to prevent the samples from oxygen contamination. All the parts of the tool in contact with the sampled solution were made by Inconel coated with Dursan.

One run of 4 SRS bottles was performed on both CX13A and CX13B zones with coiled tubing from 16 to 19th of July, 2012. There was no need for a third one. Out of 8 samplers, 7 were recovered since one sampler failed. 4 bottles were analyzed directly on Dalia FPSO, 3 were not opened and sent to France for further analyses.

### Characterization of BH sampled solutions

The analyses performed on Dalia FPSO and in France revealed that:

- The polymer was present in each zone CX13A, CX13B and CX12. The measured polymer concentration was in the same range as the injected solution (~790 +/- 30 ppm active polymer).
- The average salinity was 41g/L which is close to the salinity of the injected solution.
- The average viscosity on all samples was 1.4 cP +/- 0.2 cP at 17 s^-1 corresponding to an average degradation of 75 % +/- 6 %. Degradation is calculated according to the formula

\[
\text{Deg}(\%) = \frac{\eta_0 - \eta_{\text{deg}}}{\eta_0 - \eta_{\text{H2O}}} \times 100
\]

(Eq 1)
\( \eta_0 \)  Viscosity of the non degraded solution,
\( \eta_{\text{deg}} \)  Viscosity of the degraded solution
\( \eta_{\text{H2O}} \)  Water viscosity (0.63 cP at 50°C).

Additional degradation was found on MDT samples. Mechanical degradation would have occurred at the probe entrance during the MDT sampling due to the passage through a plugged probe as evidenced by several observations. During the operation, in-line viscosity measurement with DV rod and vibrating wire revealed to be inefficient.

- pH before and after degassing was higher than 6. For recall, viscosity of HPAM solutions starts to decrease for pH below 6.
- The hydrolysis degree was found to be approximately 30% which is similar to the initial one (27%). It means the polymer did not hydrolyze during its propagation through the formation because of the short residence time (approximately 3 months) at the field temperature (50°C).
- The iron level was found to be between 5 and 10ppm.
- Oxygen level in the samples was 0ppb.

More degradation than expected was evidenced on the Dalia polymer solution bottom hole sample of DAL753.

**Discussion of the results**

The origin of such a degradation was questioned and some additional laboratory tests were completed. There are 3 main sources of potential degradation of the polymer solutions:

1. **Bio degradation:** in the presence of bacteria, HPAM are pretty stable. Compatibility of the polymer with the injected biocide was checked.
2. **Chemical degradation:**
   - **Oxidative degradation** due to the presence of dissolved oxygen and reduced iron at the injection (Levitt et al., 2011, Seright and Skjevrak, 2014). This degradation is rapid and levels off once all the oxygen has been consumed. During injection, constant monitoring of dissolved oxygen at the riser departure on Dalia FPSO indicated values below 10ppb. This cause of degradation can thus be discarded.
   - **Thermal degradation** due to the hydrolysis of acrylamide monomers with time and temperature, leading to a precipitation of the polymer in the presence of divalent cations such as Calcium and Magnesium (Levitt and Pope, 2008, Seright et al., 2010). As seen on Figure 10, long term aging tests in anaerobic conditions indicates that polymer viscosity is stable over years in synthetic Dalia desulfated sea water at 25g/L and injection water at 52 g/L (mix of sea and production water containing divalent cations). The presence of oxygen scavenger (sodium bisulfite) does not affect the aging process. The presence of iron 2 with an initial minute amount of dissolved oxygen causes a rapid degradation that level off once all the oxygen is consumed. Viscosity is then stable over 5 years. The sudden viscosity drop of solutions in 25 and 52g/L brine after 1300 days is due to oxygen ingress in the aging capacity. After 5 years, the hydrolysis degree of the polymer aged in the 52g/L brine is around 40-45% explaining the stability of the solution.
This cause of degradation can thus be discarded.

3. **Mechanical degradation:**
   Because of the elongational component of the flow when passing through a porous medium, HPAM chains are stretched in the flow direction. At high strain rate, multiple chain breakage occurs, which results in a viscosity loss.

   For a given flow geometry, strain rate is correlated to the shear rate. For that reason, mechanical degradation in a given geometry can be predicted from shear rate estimation.

   All the critical shearing events that could lead to mechanical degradation of the polymer were reviewed (pump, transport in pipe, choke, well screen, entrance in the porous medium).

   The choke at the sea bottom was the most ‘shearing’ equipment (shear rate \(> 105 \text{ s}^{-1}\)). Degradation tests were performed on a 6” Dalia choke valve. Results indicated that degradation is function of the pressure drop through the choke. Above 5 bars, the polymer degradation is higher than 50%. During polymer injection, it was thus required to work with chokes fully opened in order to prevent the polymer from extensive degradation.

   The shear rate was evaluated at different locations over the injection process: transport in the flow line and the well (10-100 s\(^{-1}\)), wire wrapped screens (10-100 s\(^{-1}\)), 2.5” downhole injection valve (1000 s\(^{-1}\)), wellbore interface (100-1000 s\(^{-1}\) assuming a skin value of 0). Based on lab experiments, minor mechanical degradation was expected (a conservative value of 25% was taken).

   However, produced water is reinjected on Dalia, which lead to a near wellbore impairment of DAL-713 (see section above). The pressure build up due to the damage of the near wellbore is generally characterized by a skin. The basic parameters for evaluating the shear rate in a porous medium are the flow rate, the permeability, the porosity, the oil saturation and the relative permeability to water. It is thus crucial to convert this skin in permeability profile around the well.
in order to evaluate the shear rate at the entrance of the porous medium.

**Methodology to assess mechanical degradation at sand face**

First, it is necessary to estimate what was the skin when the sampled polymer was injected in the injector DAL-713.

Considering the distance between the injector and the sampler, and based on reservoir modeling it is likely that the sampled polymer was injected after August 2010, when the injectivity index abruptly decreased to 10 Sm3/d/bar (Figure 5).

Thorough Fall-Off interpretations enabled to monitor the growing area of the polymer flooded zone around DAL713. The derived best evaluation of the product “RRF * $\mu_{\text{polymer}}$” is 1.8. With the measured sampled in-situ viscosity of 1.4 cP at low shear rate, it corresponds to an RRF of 1.3, leading to a best estimate of the mechanical skin after August 2010 equal to 15. With such parameters, 70% of the draw down is due to a near wellbore effect.

In order to convert the value of skin into a permeability impairment profile, allowing to evaluate a shear rate profile around the injection well, a solids filtration model has been used, based on other observations on Block 17 injectors, where permeability changes related to PWRI injection could be nicely correlated to the amount of solids injected in the formation.

The solids filtration models estimates a profile of permeability damage around the injector as a function of the cumulative mass of injected solids according to the following law:

$$\frac{k_0}{k_d} = 1 + \alpha (m_s / A)$$  \hspace{1cm} (Eq 2)

- $k_0$ Initial “virgin” permeability.
- $k_d$ Damaged permeability
- $m_s$ Cumulative mass of injected solids
- $A$ Swept area

The reference II of 10 Sm3/d/bar can be matched with various combinations of $\alpha$ and $n$, but they result in very similar permeability profiles; an example is showed here after in Figure 11.

![Figure 11—Permeability profile around DAL713 wellbore due to PWRI damage to match the actual II after August 2010](image)

Within few meters, the permeability of the polymer flooded zone around the injector area is equal to the initial one, but due to PWRI the permeability at sand face should be degraded down to 30 to 40 mD.
In order to convert that permeability profile into a shear rate profile, the Zaitoun model has been used:

\[
\text{Shear rate} \left( \text{s}^{-1} \right) = \frac{4 u \alpha}{R_p}, \text{ with } \alpha = 2.5 \tag{Eq 3}
\]

\[R_p = \frac{8 \text{ Keff}_w}{\sqrt{\text{Porosity}}} \tag{Eq 4}\]

\[U = \text{VD} \div \text{Porosity}^*(1 - \text{Sorw}) \tag{Eq 5}\]

\[\text{VDarcy} = \text{Upolymer} = \text{Uw} = \frac{Q_p}{2 \pi r \text{Hnet}} \tag{Eq 6}\]

Keff permeability (m2)
Porosity (fraction),
Sorw residual oil saturation to water (fraction)
Qp Injection rate of polymer solution (m3/s)
r distance to the injector (m)
Hnet net height at the injector (m)

In this model, we consider that the porosity is not much changed by the PWRI solids, but the pore radius is computed as a function of the degraded permeability. The resulting maximum shear rate with the actual \(\sim 700 \text{ m}^3/\text{d}\) of injection is \(\sim 2 \times 10^4 \text{ s}^{-1}\). The following profile of shear rate and pressure drop as a function of the distance from the wellbore shows that the maximum shear rate decreases very rapidly within 10-30 cm into the formation.

Extensive work has been done in order to better understand mechanical degradation of HPAM in porous medium (Seright, 1983). Most recent internal experimental investigation (Jouenne et al., 2015), working on capillary - frits - (one pass / several passes) and pieces of cores indicates that degradation would occur passing through less than 1 cm of porous medium in frontal injection, and stay steady in the remaining of the core length. In other words, the first centimeter of porous medium determines the level of degradation, there is no more degradation on longer distances. Based on these results, very high
degradation can be encountered on a polymer solution flowing through a few centimeters at a shear rate of $2 \times 10^4 \text{ s}^{-1}$.

Based on Dalia experience and TOTAL in-house expertise, mechanical degradation at the near wellbore is considered as the main source of polymer degradation. This degradation is due to permeability impairment observed on the DAL-753 samples and caused by the bad quality of produced water reinjection.

This result highlights the important role that near-wellbore damage can have on polymer degradation.

**Conclusions**

The Polymer Injection Project on Dalia field, one of the main fields of Block 17 in deep offshore Angola, is a world first for both surface and subsurface aspects. A very successful single injectivity test was completed first quarter of 2009, just two years after first oil.

The derisking strategy identified that a larger pilot was necessary to confirm long term operability and injectivity of polymer in the specific conditions of this deep-offshore development, and measure the in situ viscosity (sampler well) of the injected polymer solution away from the injector, as key inputs to the evaluation of an extended project.

- From February 2010 to August 2012, 7 millions barrels of a 900 ppm polymer solution was injected through the three wells of the line.
- Excellent quality polymer solution has been prepared all through the pilot duration, meeting every specification from QA/QC (mainly O2 content, filter ratio, insoluble content, viscosity).
- Still the skid operability was not ideal, the skid uptime being over 80%, but at the expense of intensive efforts from the operational teams, and the maximum operated rate being 10% below the specifications.
- Long term Injectivity has been proven excellent on the horizontal wells.
- Injectivity on deviated well was excellent when polymer solution was diluted with desulfated water, but a significant injectivity index decrease was abruptly observed on the deviated well DAL-713.
- Different attempts in order to restore the injectivity by injecting slugs of desulfated sea water were unsuccessful, but no further decrease of injectivity index was observed until the end of the polymer injection. The decrease is attributed to the bad quality of the PWRI (produced water) used at that time to dilute the polymer solution.
- In summer 2012, a sampler well was drilled 80 m far from one of the injector, located behind the polymer front thanks to 4D seismic monitoring.
- MDT and bottom hole samples were successfully taken and analyzed.
- Salinity and polymer concentration of the samples were in line with expectations and confirmed that the sampler well was located at the rear of the polymer front,
- Viscosity measurements indicated a lower viscosity than expected typically $1.4 \text{ cP} \pm 0.2 \text{ cP}$ at $17 \text{ s}^{-1}$, roughly half of design
- Thorough analysis and additional studies were done: based on Dalia experience and TOTAL expertise, mechanical degradation at the near wellbore is considered as the main source of polymer degradation observed on the DAL-753 samples, and is due to permeability impairment caused by bad quality produced water reinjection
- This result highlights the important role that near-wellbore damage can have on polymer degradation.

The pilot answered to its objectives, and the key deliverables were:

- How to operate the whole process chain of viscosified water at topsides level
A better knowledge of polymer degradation from topside to deep in the reservoir
Data to properly size an extended polymer project.

This pilot led to noteworthy developments in both our fundamental and operational knowledge of polymer injection.

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