The ‘tight gas’ challenge: appraisal results from the Devonian of Algeria


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ABSTRACT: Projected future increases in Algerian gas production will, in part, come from more complex reservoirs within the Ahnet-Timimoun Basin; here, conventional quality reservoirs (>1 mD) are interbedded with volumetrically significant, low permeability sandstones (<1 mD) – the ‘tight gas’ sandstones. The challenge has been to develop a programme of work which will establish reserves in this sub-millidarcy resource; on balance, the results of this evaluation programme are positive.

The main tight gas sections are of Lower Devonian age. Grain rimming chlorite cement within thin intervals locally inhibited later pervasive quartz cementation; the quartz is the cause of reservoir degradation in the bulk of the sandstone resulting in permeabilities of <1 mD, and often in the microdarcy range. Generally, the Lower Devonian has a low density of faulting and fractures; open and closed fractures are observed in core, whilst mud losses suggest some fractures are conductive in the subsurface.

One of the main structures, the Teguentour Field, has been evaluated through the drilling of two new wells. The first of these wells (Teg-14) evaluated interbedded tight and conventional sandstones, whilst the second (Teg-15) was a dedicated tight sandstone completion involving an induced fracture programme.

The permeability range in the tight gas sandstones extends below the resolution of conventional porosity/permeability measurement; determination has been improved through mercury injection derived permeabilities. Water saturations determined from core and log suggest gas may be present in the low permeability rock. The presence of gas could not be confirmed by formation tester samples and thus dynamic data were required from the Teg-15 well which was completed within the tight sandstone interval; only the top 5 m was perforated to limit the possibility of a communication pathway down to conventional quality sandstones. After nitrogen lift, the well flowed gas to surface at \( \frac{5}{10^4} \) SCFD for several hours. The low leak-off coefficient determined suggests there was no connection to a pervasive conductive fracture network, although fractures intersected by the wellbore may have contributed to flow. Also, large poro-elastic back stresses indicate that a connection to high matrix or fracture permeability was unlikely. On balance, the test is a positive indicator of gas presence in very low permeability/porosity rocks which may recharge associated conventional layers following sufficient drawdown.

KEYWORDS: low permeability reservoir, tight formation gas reservoir, Devonian, induced fracture, Algeria

INTRODUCTION

Algeria currently produces in excess of \( 50 \times 10^9 \) SCM gas per year, much of which is exported to Central and Southern Europe, making it one of the main regional gas suppliers. This volume is predicted to increase to over \( 60 \times 10^9 \) SCM a\(^{-1}\) (Achache et al. 1998) as opportunities are taken to place additional volumes into the expanding European gas market.

Some of this additional resource will be derived from the low permeability, complex hydrocarbon reservoirs within the Ahnet-Timimoun Basin (Fig. 1). This area, referred to as District-3 for administrative purposes, covers more than 100,000 km\(^2\) and lies in the Central Sahara centred on the town of In Salah. The north of the area of interest is some 520 km south of the Hassi R’MEL ‘super-giant’ gas field; this field is the nearest infra-structure for gas export. Initial exploration activity commenced in this region during the 1950s (Traut et al. 1998) and demonstrated its prospectivity with some 40 gas discoveries recorded from more than 60 exploration wells. However, the enormous production potential of Hassi R’MEL (Magloire 1970; Maggregor 1998) was initially adequate to meet gas demand from Europe; this, combined with the remoteness of the District-3 area, and its lack of infra-structure have, until now, prevented any serious attempts to develop these discoveries.
More recently, joint studies between Sonatrach and BP Amoco have indicated the potential for a commercial gas project based on several of the discoveries within District-3. This led to an agreement between Sonatrach and BP Amoco, which committed the joint venture between the two companies (In Salah Gas Project) to an initial 30-month Exploration & Appraisal programme which was completed in 1999.

The main gas fields within the project area are typically large low relief structures of significant areal extent (up to 500 km²). The primary reservoirs comprise multiple, conventional quality (>1 mD), gas-bearing sandstones; these targets are mainly of Devonian age (D10 to D55; Fig. 2; Myers & Hirst 1995) with a single productive horizon of Carboniferous age (C10.2). Individual reservoirs are relatively thin (1–20 m thick) and variable in their lateral extent and quality. In addition, volumetrically significant sections of non-conventional reservoir were hypothesized as being potentially gas bearing. The bulk rock volume associated with this non-conventional ‘tight gas’ resource required an early evaluation to assess the impact on the scope and potential of the overall development.

The challenge has been to develop a programme of work which will provide confidence as to the reserves from the ‘tight gas’ resource. This activity forms the basis of this paper and concentrates on the potential within one of the main structures, the Teguentour Field.

**TEGUENTOUR FIELD SUMMARY**

The Teguentour Field (Fig. 3) is a large low amplitude inversion anticline. The reservoirs comprise a series of Carboniferous and Devonian sandstone reservoirs and mudstone seals. Source rocks are of Silurian and Upper Devonian age (Fig. 2). Prior to the joint venture appraisal by In Salah Gas (1997–9), 13 wells were drilled on and around the structure following its discovery in the late 1950s. Fluid samples taken show this reservoir contains dry gas with <10% CO₂. As part of the appraisal programme, two additional wells have been drilled, Teg-14 and Teg-15.

**Depositional summary**

The D10 to D30 (Gedinian) sequence is predominantly of marine origin, with sandstone deposited mainly within a shoreline complex. Slight variations in sea-level caused the lateral translation of the shoreline back and forth across the gently northward-dipping Devonian shelf margin. The resulting sequence comprises an alternation of the sand-prone shoreface deposits and finer-grained shelfal sediments. The sandstones, which range from <2 m to up to 15 m thick, are generally vertically isolated from each other by the finer-grained shelf deposits. This stacked sequence of multiple potential reservoir sandstones is further complicated by the laterally discontinuous nature of some units over distances of hundreds of metres to a few kilometres.

This period of marine deposition was abruptly terminated by a major fall in sea-level at the beginning of Siegenian times (D40 sandstone; Fig. 2). This resulted in the regional deposition by braided rivers of a sheet of high netgros sandstone (Beuf et al. 1971). This fluvial sandstone is typically >100 m thick with only minor siltstone and mudstone layers deposited during marine incursions; these potentially act as local barriers or baffles to vertical flow. Siegenian sandstone deposition was terminated by a further marine transgression which deposited...
The sandstones are generally quartz arenites with monocrystalline quartz dominating the framework grains; other detrital components such as feldspars, rock fragments and ductile grains are typically cumulatively <10%. Thus, at deposition, the sandstones mostly had excellent reservoir potential and the D40 fluvial sandstone, in particular, would have been an extensive tank of porous sandstone. The burial history and the elevated temperatures experienced in the basin (Logan & Duddy 1998) have resulted in extensive diagenetic modification of the depositional fabric. Pressure solution caused dissolution of silica as indicated by annealed quartz grain contacts and frequently developed dissolution seams (stylolites). Much of the silica was redeposited within pore spaces; as a result reservoir quality for much of the sandstone is less than 7% porosity and 1 mD permeability – the ‘tight gas’ sandstones. However, locally there was a very early development of a clay cement. The typical morphology of these chloritic clays was a thin rind covering the mainly quartz detrital grains. The chlorites formed early in the burial history (within the first few hundred metres) and certainly much earlier than the quartz cements. Their presence has proven to be very important as they effectively armoured the detrital grains from subsequent quartz nucleation; pressure solution at grain contacts may also have been inhibited by the rinds of chlorite.

The formation of the early chlorite is related to pore water geochemistry in the near-surface sediment and is favoured where there is intense iron reduction and low sulphate concentration. Such conditions may exist where pore waters of fluvial and marine origin mix. During the Siegenian, periods of marine incursion in the overall fluvial-dominated sequence may have resulted in the development of extensive (tens of km²) but potentially thin chloritized zones within the transgressed substrate. The net result is a sequence of essentially tight sandstone but with thin conventional quality layers prevalent in the lower part (Fig. 4). These conventional quality layers, which are well developed in the Lower D40 of Teg-14 (Fig. 5), may prove to be attractive targets for gas accumulation.

**Fig. 3.** Teguentour Field structure at top D40 level.

**Fig. 4.** Teguentour Field, D40 (Siegenian) reservoir model.
significant in any gas production from the tighter zones dominating the Upper D40.

FAULT AND FRACTURE EVALUATION

The top D40 structure map shows there are no significant faults (Fig. 3). However, the existing 2D seismic dataset over the Teguentour structure is spaced at $2 \times 3$ km allowing only a broad definition of the fault pattern. In addition, resolution of faults with displacements of less than 20 m is not currently possible due to the low frequency content of the seismic data.

Early core studies confirmed the presence of fractures in the D40 succession. Whether these fractures would facilitate production from the tight formation or act as barriers to flow was a significant uncertainty. To address this, a number of studies were carried out.

Devonian core description

Fractures from all available D40 core in the Teguentour Field were described. Fracture densities vary from six fractures per metre to one fracture every 4 m, although their apertures remain largely unknown. A proportion (0–-44%) of fractures appear to be wedged open by various forms of partial cement fill, whilst a similar range of fractures were totally cemented (0–-38%). However, many fractures described from core had no cement and many of these are potentially drilling-induced. Direct measurements of fracture aperture from the core are not considered representative of likely apertures under reservoir conditions. Most fractures are steeply dipping ($75^\circ$ to vertical) and no relation between fracture dip and cement presence was noted. Intersecting fractures are locally observed in core; this intersecting geometry favours the likelihood of there being a connected fracture network.

Integration of core description and image log analysis on Teg-14

In Teg-14, an image log (UBI) was run over the entire reservoir section. A significant proportion of the D40 section was cored (c. lower half) allowing a calibration of the image log; over the cored interval 79 fractures were identified with an average fracture density of 1.2 m$^{-1}$ (Table 1; Fig. 6). Steeply dipping uncemented to partly cemented extensional fractures dominate in this well. Cemented fractures and polished/striated bed-parallel mudstone shears were also recognized. The fractures have a dominant NW–SE orientation (Fig. 7). An average lateral fracture spacing of less than 30 cm is estimated; apertures of part-cemented and uncemented fractures are <1 mm and typically <0.1 mm at surface conditions; their condition under reservoir conditions is uncertain.

Fracture modelling

Fracture modelling was based on observations from core. A sector model of the D40 interval was created to understand the

Table 1. Description of fractures in Teg-14

<table>
<thead>
<tr>
<th></th>
<th>C10</th>
<th>D55</th>
<th>D40</th>
<th>D30</th>
<th>Total</th>
<th>All intervals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. fractures</td>
<td></td>
<td>9</td>
<td>79</td>
<td>9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Core length (m)</td>
<td></td>
<td>9.10</td>
<td>66.58</td>
<td>38.58</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average fracture density (m$^{-1}$)</td>
<td></td>
<td>1.0</td>
<td>1.2</td>
<td>0.23</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Types*</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. cemented</td>
<td></td>
<td>2 (22)</td>
<td>8 (10)</td>
<td>0</td>
<td>10 (10)</td>
<td></td>
</tr>
<tr>
<td>No. part-cemented</td>
<td></td>
<td>2 (22)</td>
<td>27 (34)</td>
<td>0</td>
<td>29 (30)</td>
<td></td>
</tr>
<tr>
<td>No. uncemented</td>
<td></td>
<td>5 (56)</td>
<td>41 (52)</td>
<td>9 (100)</td>
<td>55 (57)</td>
<td></td>
</tr>
<tr>
<td>No. bed-parallel shears</td>
<td></td>
<td>0</td>
<td>3 (4)</td>
<td>0</td>
<td>3 (3)</td>
<td></td>
</tr>
<tr>
<td>Average spacing</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All fractures (cm)</td>
<td></td>
<td>27</td>
<td>45</td>
<td>28</td>
<td>136</td>
<td>42</td>
</tr>
<tr>
<td>Uncemented and part-cemented (cm)</td>
<td></td>
<td>27</td>
<td>65</td>
<td>29</td>
<td>136</td>
<td>45</td>
</tr>
<tr>
<td>Uncemented only (cm)</td>
<td></td>
<td>27</td>
<td>126</td>
<td>35</td>
<td>136</td>
<td>73</td>
</tr>
</tbody>
</table>

*Percentage in parentheses.
impact of fracture aperture, spacing, length and connectivity.

Two main conclusions were drawn from this modelling. Fracture aperture is the critical uncertainty and thus a range of apertures were modelled. For apertures >0.001 mm, fracture permeabilities are likely to be >10 mD. Partially cemented fractures noted in core locally exceed this dimension and such fractures should have a significant contribution to gas flow into the wellbore if they form a connected network.

Fracture densities of >1 fracture per metre, assuming a level of connectedness indicated by core and field studies, would produce fracture network permeabilities of >10 mD.

Mud losses
Mud losses in the Teguentour Field (Table 2) show that about half the wells experienced losses which are likely to be related to fractures. Losses tended to be over relatively thin intervals, were of a small volume and cured quickly. The inference is that these losses were due to small open fractures or a poorly connected fracture network of limited stratigraphic range.

Test vs. core $K_h$ studies
Test permeabilities, when compared with core-derived permeabilities resulted in a good match in most wells for the conventional pay in the Lower D40. However, in Teguentour typical test permeabilities are in the order of 2000 mD feet and any fracture contribution is likely to have been masked by flow from the matrix porosity of the conventional quality layers.

Fracture summary
Natural fractures have been identified in the Upper D40 low permeability sequence in Teg-14 and some of the earlier wells. They include some which are mineralized and at least partially open. The mud loss data from around the field would suggest some of these fractures are conductive in the subsurface. If gas can be demonstrated within the low permeability matrix, fractures may act as conduits for flow into a borehole.

PETROPHYSICS

Porosity and permeability estimation
Porosity has been estimated using the sonic log which has been calibrated to core data. The sonic log has been selected because it is the tool which is least affected by gas presence and also because of the poor hole conditions due to borehole breakout in many of the wells. However, in low porosity gas reservoirs, the effective porosity derived from wireline data is close to the resolution of the porosity log.

Sub-millidarcy rock has historically been evaluated by conventional core analysis; resolution has been poor and the consequent porosity–permeability transforms are poorly constrained. To address this problem, mercury injection analyses have proved to be the most effective method in defining sub-millidarcy permeabilities. The validity of the mercury injection data is demonstrated by comparison with the conventional data over the better quality intervals (<1 mD; Fig. 8) and this in turn gives support to the relationship determined for the low porosity/permeability rock.

Gas saturation
The nature of the tight gas sandstones means that in terms of true resistivity ($R_t$), it is difficult to distinguish between a porous
sand (with or without gas presence) and a non-porous sand. The $R_t$ are in the range of 150–250 Wm and therefore the fluid type present in low porosity rock is difficult to determine as this represents a small percentage of the total resistivity signal measured by any of the resistivity logs. It is for this reason that a water saturation from core study has been performed in order to assess the fluid type. The comparison of the log and core saturation (Fig. 5) suggest that gas is present in the low permeability rock; however, the accuracy of the water saturations remain equivocal given the large errors associated with both core and log measurements on low porosity material. This is particularly so for the log evaluation as the low porosities encountered mean that the $S_w$ calculation will be extremely sensitive to the value of cementation exponent ($m$) selected; this exponent remains poorly constrained.

The mercury injection measurements that have been used to provide the sub-millidarcy permeability data have also yielded pore throat size distribution and capillary pressure data. A typical capillary pressure curve (Fig. 9) reveals that if a sufficient height above the field-wide free water level is achieved, it is possible for gas to enter the pore system encountered in Teg-14; because the pore throat size distribution is defined in a narrow range, gas will enter all of the pore throats at a similar height above free water level. It will then desaturate to an irreducible water saturation over a further short height increase. Again, this is due to the narrow range of pore throat sizes and also the large density difference between gas and brine, where capillary forces are far stronger than viscous and gravitational forces.

The presence of gas was not confirmed by formation tester samples as the permeabilities being tested were beyond the limit of the tool design. Neither sample nor pressure data were obtained due to the low permeability of the formation. Poor hole conditions were a further problem; the brittle nature of the low permeability rock caused it to break out as formation stresses were relieved into the borehole.

How will the gas flow?

As previously stated, the permeability range in the tight gas sands was not well understood from conventional porosity/permeability measurement but following evaluation of Teg-14 has improved through mercury injection derived permeabilities. However, these results are a static description of small pieces of the reservoir prone to coring-induced artefacts, such as micro-fractures, which may have enhanced the laboratory data. Therefore dynamic data were required to confirm not only the presence of gas, but also the production mechanism – whether via matrix or fracture permeability or a combination.

### Table 2. Teguentour Field mud losses

<table>
<thead>
<tr>
<th>Well</th>
<th>Loss zone</th>
<th>Losses</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Teguentour15</td>
<td>No losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour14</td>
<td>C10.2</td>
<td>Maximum of 1069 m$^3$ h$^{-1}$</td>
<td>Coring</td>
</tr>
<tr>
<td>Teguentour12</td>
<td>D40(U)</td>
<td>10 m$^3$ h$^{-1}$/b</td>
<td>Reaming</td>
</tr>
<tr>
<td>Teguentour11</td>
<td>D40(U)</td>
<td>500–1500 m$^3$ h$^{-1}$ in D40/b</td>
<td>Reaming</td>
</tr>
<tr>
<td>Teguentour10</td>
<td>D40(U)</td>
<td>Total losses of 41 m$^3$</td>
<td>Not stated</td>
</tr>
<tr>
<td>Teguentour9</td>
<td>Poor data, no record of losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour8</td>
<td>Poor data, no record of losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour7</td>
<td>Poor data, no record of losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour6</td>
<td>Poor data, no record of losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour5</td>
<td>Poor data, no record of losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour4</td>
<td>No losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Teguentour3</td>
<td>D20</td>
<td>Losses of 1.5 m$^3$ h$^{-1}$ in the Gedinnian</td>
<td></td>
</tr>
<tr>
<td>Teguentour2</td>
<td>D40/D50</td>
<td>&lt;500 l h$^{-1}$/b</td>
<td>Drilling</td>
</tr>
<tr>
<td>Teguentour1</td>
<td>D40/D30</td>
<td>54 m$^3$ total/b</td>
<td>Testing</td>
</tr>
</tbody>
</table>

Fig. 8. Teguentour Field porosity–permeability cross-plot.
Tight gas appraisal, Algeria

Fig. 9. Mercury injection capillary pressure (MICP) data from the Teg-14 well.

**DYNAMIC DATA**

Historically, there are little production data from within the tight reservoir section; much of the early appraisal effort was focused on the conventional quality reservoir. Tests undertaken in the Teg-9 well over the mostly tight Upper D40 reservoir section produced gas to surface at rates which were not measured but estimated at approximately 0.5 MCFD for several hours before being shut-in. No test analysis was performed, since at these low rates the well was still cleaning-up. A leak-off coefficient of 0.0007 ft min$^{-0.5}$ was measured for the 50 lb cross-linked borate fluid (introduced as part of the displacement fluid). This low value is fully consistent with that predicted from Upper D40 matrix properties and suggests that connection to a pervasive conductive fracture network was not seen. However, this does not exclude the possibility that fractures intersected by the wellbore have contributed to flow.

Large poro-elastic back stresses were created during the three injection treatments in which a total of 228 BBL of material was pumped. Closure pressures increase by nearly 1000 psi, from 0.58 to 0.67 psi ft$^{-1}$ (Fig. 11), as did the treatment pressure which increased by 1900 psi over the course of the three cycles. Rebounds in the bottom hole pressure of up to 1400 psi were also recorded after opening the well to atmospheric pressure (Fig. 11). These poro-elastic back stresses suggest that the fracture has not connected to a substantial volume of high permeability. Such a connection would have caused the rebound pressures to dissipate rather than a build-up in pressure after shut-in.

On balance, the observed responses of this fracture treatment indicates gas was sourced from the matrix and not a conduit (fracture) down into the Lower D40 reservoir interval. While not definitive proof of a process of production, it is a positive indicator of gas presence in very low permeability/porosity rocks.

early well. However, in Teg-14 and, subsequently, Teg-15, this section was found to be primarily made up of sandstones in the 1–4% porosity range, with the majority of the section comprising 1–2% rock (Fig. 4). As a consequence, the predicted well potential was reduced by some 85% as estimated sandstone permeabilities of 0.11–0.007 mD were reduced to 0.007–0.00005 mD (Fig. 8).

To limit the possibility of a communication pathway from the wellbore in Teg-15, to the conventional sands predicted within the Lower D40 reservoir section (Fig. 4), this well terminated high in the section within the tight interval (Fig. 10). Similarly, to limit the likelihood of the induced fractures (the frac. programme) propagating down into the lower conventional sands, only the top 5 m of the Upper D40 tight sandstone sequence was perforated. The frac. programme was in three parts:

(1) an initial breakdown test during which fluid was pumped into the well to obtain the initial fracture pressure;
(2) a data frac. during which fluids were pumped into the formation to obtain fracture performance characteristics;
(3) the main propped frac.; fluids and propant pumped into the formation.

In the initial breakdown test, 11 BBL of surfactant treated water were pumped, recording a breakdown pressure of 10 668 psi, while during the data frac., 70 BBL of displacement and 40 BBL of gel were pumped and a lower breakdown pressure of 10 307 psi was recorded (Fig. 11). After each treatment the well was displaced to nitrogen, but failed to flow gas to surface. The main frac. involved 70 BBL of displacement (i.e. fluid used to clean and open the frac. ahead of the propant) and 32 BBL of gel with 500 lb of propant placed into the formation. The final induced fracture geometry was predicted as having a hemispherical shape and a maximum fracture height of c. 60 m retaining an estimated 20 m fracturated interval above the prognosed higher porosity Lower D40 interval (Fig. 12). After nitrogen lift, the well flowed gas to surface at 50 × 10$^3$ SCFD for several hours before being shut-in. No test analysis was performed, since at these low rates the well was still cleaning-up.

Fig. 11. Mercury injection capillary pressure (MICP) data from the Teg-14 well.
DISCUSSION

Evaluation of several of the fields within the Ahnet-Timimoun Basin indicated the presence of large volumes of sub-millidarcy sandstone which was potentially gas bearing. The bulk rock volume associated with this non-conventional 'tight gas' resource required an early evaluation to assess the impact on the scope and potential of the overall development. This resulted in the drilling of two new wells from which previously unavailable data were obtained; these new data include image logs to assist with fracture definition, mercury injection analysis, Sw assessment directly from core, an extended well test over the Lower D40 conventional sandstones and an induced fracture programme targeting only the tight gas sandstones.

Core from the first of these new wells, Teg-14, confirmed the presence of thin intervals of conventional quality reservoir near the base of the D40 (Siegenian) interval. These good quality intervals, in which chlorite inhibited later quartz cement, have been hypothesized as being related to flooding events and were therefore likely to be laterally extensive. An extended well test confirmed this sedimentological hypothesis. The cores also confirmed the presence of significant well-cemented sandstone with low porosity (<4pu) in the Upper D40. This core was compared with an image log (UBI) which was run over the entire reservoir. Steeply dipping uncemented to partly cemented extensional fractures dominate in this well with a dominant NW–SE orientation. Mud loss data from across the Teguentour Field would suggest some of these fractures are conductive in the subsurface. If gas can be demonstrated within the low permeability matrix, fractures may act as conduits for flow into a borehole.

Within the Teguentour Field, sub-millidarcy rock has been historically evaluated by conventional core analysis. Results, particularly in the tighter rock tend to be of low accuracy with poor porosity–permeability transforms resulting. In Teg-14, mercury injection analyses have provided an alternative methodology for determining permeabilities and also enabled the poro-perm transform to be extended with some confidence into the sub-millidarcy realm. The capillary pressure curve derived from the same mercury injection measurements reveals that if a sufficient height above the field-wide free water level is achieved, it is possible for gas to enter the pore system. Complementing these data, a water saturation from core...
study has been performed suggesting that gas is present in the low permeability rock in Teg-14. All the above static descriptions from Teg-14 provide a detailed understanding of the D40 interval but do not unequivocally demonstrate gas as a mobile phase within the tight gas sandstones. Therefore dynamic data were required to confirm the presence of gas and also the possible production mechanism – whether via matrix or fracture permeability or a combination. For the subsequent Teg-15 well, the understanding gained from Teg-14 was such that a tightly constrained borehole could be planned and a dedicated completion within the tight sandstone interval achieved. Although the rates were low, post-fracturing, Teg-15 flowed gas to surface at c. $5 \times 10^3$ SCFD for several hours before being shut-in; given the degree of understanding of the sequence and the detailed evaluation of the fracture programme, it is considered the gas was sourced from the matrix and not a conduit (fracture) down into the Lower D40 reservoir intervals.

The evaluation programme has demonstrated that, on balance, gas exists within the very low permeability/porosity rocks. The association of the large volume of tight sandstone with conventional quality layers in the Lower D40 points to a possible, but unproven, production mechanism whereby gas from the tight intervals could recharge these deeper, conventional layers following sufficient drawdown.

We would like to take this opportunity of thanking the many team members who have contributed to this complex discussion. In particular to Y. Abada, A. Aissaoui, C. Dyke, J. Earnshaw, P. Fleming, C. McGill, T. Needham and M. Ward who have been actively working on this problem in the In Salah Gas Project. We would also like to thank Sonatrach and BP Amoco for permission to present this work.

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