Trap Oil Ltd

Relinquishment Report

for

Licence P.1938

Blocks 3/2c, 4c, 7d, 9c, 13b, 14h, 14j, 16/12b, 17c, 211/22b, 27d, 28b & 29e

Relinquishment date: 31 December 2014
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| Licence number | P1938 |
| Licence round  | 27th  |
| Licence Effective date | 01 January 2013 |
| Licence type    | Promote |
| Block number    | 3/2c, 4c, 7d, 9c, 13b, 14h, 14j, 16/12b, 17c, 211/22b, 27d, 28b & 29e |
| Operator        | Trap Oil Ltd |
| Licensees       | Trap Oil Ltd 100% |

Work programme

Firm commitments

- obtain 12,000 km of 2D seismic data
- obtain 4,900 km of 3D seismic data
- carry out core analysis and fluid characterisation studies

Drill-or-drop

- drill one well to 3350m to evaluate the Upper Jurassic Kimmeridge or Heather Clay Formation

All working obligations have been fulfilled.

2. Synopsis and introduction

The Promote Licence was awarded in the 27th Licensing Round (2013) to Extract Petroleum Ltd. Extract comprises Mr Robert Birdsong and Dr Chris Cornford, both of whom have a long term working relationship with key former members of the management team of Trapoil. Trapoil sponsored Extract to undertake technical studies to allow an application to be made in the 27th Licensing Round for acreage that would allow for the exploration of the unconventional potential within the organically rich and thermally mature Kimmeridge Clay and Heather formations in the central and northern North Sea.

A farm in agreement between Trapoil and Extract was executed on 27.04.12 (ahead of the licence round submission) to enable Trapoil to farm in to the licences upon successful award. Subsequent to the award of the licences to Extract, a Royalty Agreement covering all licences was executed on 18.01.13, granting Extract an overriding royalty of 1% on any production.

The blocks are located in the South Viking Graben, the North Viking Graben and the East Shetland Basin in areas of mature late Jurassic Kimmeridge Clay and Heather formations. Trapoil participates with a 100% working (paying) interest. Extract Petroleum has a 1% overriding royalty.
3. Exploration Activities

3.1 Summary

Conventional source rock analyses show that the Kimmeridge Clay Formation of the UKCS contains large volumes of residual (i.e. unexpelled) oil where buried below approximately 3 km (9,850ft). Free oil yields from both Rock-Eval pyrolysis and solvent extraction average at c. 6 kg per tonne of rock with a range from 3 – 9 kg per tonne. Unlike most onshore basins where the source rocks have been uplifted and hence generation has ceased, the North Sea basin, with rapid Tertiary-Recent sedimentation, offers the opportunity to drill directly into an actively generating, world class, oil-prone source rock that contains or is interbedded with a high clastic content (siltstone, sandstones and finely laminated sand shale sequences comprising a “hybrid” reservoir sequence.

It is postulated such a sequence is an ideal candidate for hydraulic fracturing (“fracking”) and for testing the offshore “unconventional” or “hybrid” reservoir concept in the North Sea grabens.

Existing seismic surveys define the area and thickness of the hybrid reservoir while thermal modelling defines the maturity constraints, calibrated against thermal and maturity data from adjacent wells. Limits are placed on the lithologies (mineralogy and rock properties) by the analyses of available conventional cores and cuttings. Integration of petrophysical based stratigraphic and lithofacies interpretations defines individual rock units or layers. Petrography and QEMscan SEM allow for characterisation of mineralogy while calculations and measurements of Young’s Modulus and Poisson’s Ratio assist fracture modelling. Production modelling suggests high initial flow rates.

The objective of maturing the studies described above was to lobby for industry support to allow a proof-of-concept well to be drilled.

The technical studies were focused on the South Viking Graben and well 16/12b-6 was identified as a type well.
3.2 Seismic Data

All available 2D and 3D seismic was obtained and mapping of the gross interval of interest (encompassing top J66C to top J74 standard J sequences (Partington et al., 1993) was undertaken. Mapping of individual lithofacies defined units proved beyond the resolution of even ‘best in class’ recently reprocessed 3D seismic data.

3.3 Stratigraphy

Using 16/12b-6 as the type well, 14 individual units or layers were defined based upon petrophysical characteristics. These layers formed the basic input for the fracture and production modelling.
3.4 Petrophysical evaluation

12 wells drilled between 1978 and 2007 were sampled and analysed. All wells have modern log suites available, with density, neutron and sonic logs together with focussed resistivity logs. Most of the wells (9 out of 12) were drilled with oil based mud and so do not have micro resistivity (Rxo) devices.

- 3/6a-1
- 3/7-3
- 3/7b-5
- 3/7a-7
- 3/13b-2
- 16/12b-6
- 16/12b-10
- 16/12b-12
- 16/12a-23
- 16/13a-3
- 16/13d-6
- 16/18b-5

No state-of-the-art logs were available such as:

- SGR (spectral gamma ray)
- NMR (nuclear magnetic resonance)
- ECS (elemental capture spectroscopy)
- FMI (full bore formation micro-imager)

Types of analysis undertaken included:

- Conventional - using traditional effective porosity system where bound water associated with shale is treated as part of rock matrix
- Laminated sand analysis using Thomas-Stieber approach, used to separate heterogeneous shaly sand into laminar sand, laminar shale and dispersed shale type (structural shale can be discerned) to allow for better determination of sand porosity
(and hence permeability) and resistivity leading to a shale corrected value of $Sw$

- Cluster analysis - used to type lithofacies
- Dipole sonic (wells 16/12a-23 and 16/18b-5) - to derive dynamic mechanical rock properties (Poisson’s ratio and Young’s Modulus)

Composite logs, mud logs and End of Well reports are available for most wells as part of the CDA database.

3.5 Sampling and analytical programme

70 core plugs and core chips from 13 wells were subjected to the following analyses:

Mechanical properties

- Density
- Young’s Modulus and Poisson’s Ratio (static and dynamic)
- Porosity
- Permeability
- Micro-hardness (sandstone and mudstone layers)

Petrographic Properties

- Thin section description
- Mineral abundance (quartz, carbonate, clay)
- Sedimentary structures
- Micro-faulting
- SEM
- QEMScan (quantitative evaluation of minerals by SEM)

Geochemical Properties

- TOC
- Rock-Eval ($S_1$, $S_2$ & $T_{max}$) plus derivative $HI$ ($S_2/TOC$ and $PI$ ($S_1/S_1 + S_2$) ratios
- Vitrinite Reflectance

It is to be noted the following database was accessed:

- Log and well reports for 47 wells
- Biostratigraphy for 14 wells
- Geochemistry reports for 3 wells
- Core sample on 13 wells with 2 only (16/17-14 & 18) having core within the interval of interest (base J66C – top J74)

In addition a database of public geochemistry from adjacent Norwegian fields (obtained from the NPD website) was used to establish maturity and generation trends.
3.6 Geochemistry

Peak generation and retention (pre-expulsion) occurs at 12,500-14,000ft. Transposing onto depth maps at top and base of interval of interest allowed the identification areas of optimum production yield.

Mapping rock temperatures using geothermal gradients allowed for the definition of areas for optimum petroleum composition (volatile oil).

4. Fracture modelling

The purpose of hydraulic fracturing or “fracking” is to increase the surface area of the formation in contact with the well bore. The fracture or “frack” is achieved by pumping a fluid into the well at very high pressure causing the formation interval of interest to split along a plane at the level of the well perforations. The “split” is then propped open by use of a suitable sand-based propant to form a large surface area in contact with the well bore.
The fracture will propagate through the rock perpendicular to the minimum horizontal stress in the formation. The orientation of stresses therefore dictates the ideal trajectory for any horizontal wells and is the reason why we propose to first induce a fracture in a vertical well to calibrate the stress orientation and gather other data for use in designing the subsequent horizontal well bores, including associated fracks.

The ultimate dimensions of any frack that can be placed in a reservoir is a function of:

- the stress contrast between layers which in turn is determined by a number of factors: the lithology of the different layers, the Young’s Modulus (pressure required to deform the rock) and the Poisson’s Ratio (axial/radial deformation)
- the leak-off coefficient, i.e. how fast the liquid being pumped leaks through the fracture walls
- operational constraints such as the frack fluid properties and pumped volumes

If the reservoir is more permeable, leak-off will be high and the frack short. This is balanced by high productivity from the more permeable reservoir. The converse is also true.

Fracture degradation over time is also an issue in the modelling of production. The reservoir models include correlations that account for this.

The fracture evaluation process will be performed in a sequence of discrete steps. It begins with a “mini-frack” in the vertical well to calibrate the Stimplan model, followed by a full frack in the same vertical well consisting of two stages, and then multiple fracks in a subsequent horizontal well.

The shape of the fracks achieved depends on the stress contrast between layers. A “low stress contrast” scenario results in fracks where height and wing length are similar giving a “short and fat” frack shape. A “high stress contrast” scenario results in fracks where wing length is several times greater than the height giving a “long and thin” frack shape. This is illustrated below.

After analysis and service company review, it was concluded that we would be in a low stress contrast environment at our proposed locations.
4.1 Fracture and reservoir simulation model inputs

As described above, lithofacies data for the J66 to J74 sequences modelled were derived from a combination of log and core analyses. Fourteen reservoir layers were defined within the interval of interest and these were further broken down into one hundred layers for fracture modelling.

Various analyses were carried out to determine and correlate Young’s Modulus and Poisson’s Ratio using available logs and core measurements. Dipole sonic logs (as in the 16/12a-23 well) provide dynamic values for comparison with core derived static values but data for both is limited. The PR versus Gamma Ray (GR) equations from the dipole sonic recoded in well 16/12a-23 were applied to the GR from type well 16/12b-6 to derive stress contrast models.

4.2 Stimplan model

Fracture Technologies Ltd. (Sami Haidar and Jose Caballero) was engaged to run the Stimplan model. Low, mid and high stress models were tested in early cases but on further consideration and peer review, all production runs were based on a low stress contrast scenario.

The Stimplan model accepts 100 layers, sufficient to ensure a realistic prediction of frack shape and dimensions. The specific input to the Stimplan Model is plotted below:

In the vertical well frack modelling, two fracks were modelled, the smaller upper one covering reservoir layers 1 to 5 and the larger lower one covering reservoir layers 6 to 14. Layers 6 and 14 are considered to be unproductive. The fracks were positioned and checked to ensure they stayed within the reservoir layers.
In the horizontal well, which in reality runs at 7° to the horizontal with a length of 5,000 feet, six small upper fracks were used with the same dimensions as for the top frack in the vertical well covering layers 1 to 5, and four larger lower fracks with the same dimensions as for the bottom frack in the vertical well covering layers 7 to 13. The frack coverage, shape and layouts are shown in the next section.

**Frack shape and dimensions**

![Fracture Shape and Dimensions Diagram]

**Frack layout in horizontal well**

![Fracture Layout Diagram]
5. Production modelling issues and caveats

As previously mentioned, the nature of the play gives rise to a number of challenges in the modelling process. Because there is no trapping mechanism in the conventional sense (if anything, it is stratigraphic) and given the lack of control points, defining the reserves that can be accessed by a given well is difficult and largely a matter of judgement. If we assume an infinitely acting reservoir, then, at the end of say 20 years, we would theoretically reach an equilibrium state where the peripheral virgin reservoir pressure of 8,200 psi remained and there would be a pressure gradient across the field to the well bore where the final bottom hole pressure was at say 2,000 psi.

In the equilibrium state, the pressure at the periphery would be insufficient to allow any more flow from the reservoir due to the natural resistance of the formation. This would be more marked in formations with very low permeability. Such a condition would show a pressure plot reminiscent of a halo as illustrated in the two diagrams below.

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi. These two pressure plots were derived using low permeability formations in order emphasize the point.

**Vertical well – 1 frack plane**

![Vertical well - 1 frack plane diagram](image)

**Horizontal well – 10 frack planes**
As stated above, for modelling purposes we are dealing with an interval of some 536 feet comprising 14 defined layers. There is a continuum of lithology represented from conventional clean sandstones, albeit thin (15ft in layer 3) to silty claystone and interlaminated sandstones, siltstones and claystones. Selecting the area to be addressed for production simulation is largely a matter of judgment and perspicacity. To illustrate the problem, we have addressed two areas per well, 8,000 feet x 10,000 feet and 12,000 x 16,000 feet. These areas have then been converted into volumes per layer by multiplying by the respective layer thickness.

For each of these areas we have derived values for available oil and oil produced allowing for the estimation of an effective recovery factor for the respective layer. Pressure depletion diagrams have been produced for several intervals from time zero to ten years. Some layers show “halo” development as above, others show complete depletion of the entire area, indicating that a larger area should be addressed.

Area addressed – 8,000 x 10,000 feet

<table>
<thead>
<tr>
<th>Layer</th>
<th>Top (ft)</th>
<th>Bottom (ft)</th>
<th>Thickness (ft)</th>
<th>Permeability (md)</th>
<th>Porosity (fraction)</th>
<th>Sw (fraction)</th>
<th>NTG (STB)</th>
<th>Available Oil (STB)</th>
<th>Oil produced (STB)</th>
<th>RF (%)</th>
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It should be noted one North Sea Block has dimensions of approximately 12 km by 18 km. If divided into 30 sub blocks, each sub block will be 2.4 km by 3 km or 8,000 ft by 10,300 feet.

**Pressure Depletion Profiles, Layer 3: 8,000 x 10,000 feet**

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.

**Pressure Depletion Profiles, Layer 7: 8,000 x 10,000 feet**

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.
Pressure Depletion Profiles, Layer 13: 8,000 x 10,000 feet

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.

The drainage patterns above rely on the assumption that the layers are laterally extensive which may not be the case. The tiger stripe formations will almost certainly have a degree of lateral discontinuity but this will be supplemented by a degree of inert sand lens juxtaposition.
There will also be a degree of layer-to-layer transmissivity which is not illustrated by the above diagrams but which is evident in the reservoir model, albeit at more or less insignificant levels.

Area addressed – 12,000 x 16,000 feet

<table>
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<tr>
<th>Layer</th>
<th>Top (ft)</th>
<th>Bottom (ft)</th>
<th>Thickness (ft)</th>
<th>Permeability (mD)</th>
<th>Porosity (fraction)</th>
<th>Sw (fraction)</th>
<th>Nig (fraction)</th>
<th>Available Oil (STB)</th>
<th>Oil produced (STB)</th>
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</table>

Pressure Depletion Profiles, Layer 3: 12,000 x 16,000 feet

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.
Pressure Depletion Profiles, Layer 7: 12,000 x 16,000 feet

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.

Pressure Depletion Profiles, Layer 13: 12,000 x 16,000

In these diagrams, the dark blue area represents virgin reservoir pressure at 8,200 psi and the green areas 4,000 to 6,000 psi. The black areas around the well bore, where the fracks are positioned, is at 2,000 psi.
Comparing the pressure depletion for layers 3 and 13, we can see that for layer 3, even with the larger area, we are not seeing “halo” development after 10 years. For layer 13, “halo” development is evident with the larger area. In these models, we are assuming that all layers are homogenous, continuous and are uniformly connected. Realistically, we know this will not be the case and there will be variations in properties across layers, areas within layers may not be continuous, particularly for conventional sandstones, and connectivity may be variable. This somewhat random interconnectivity gives rise to the modelling challenges.

To deal with this vagary we have decided to define an “optimistic case” and a “breakeven case” to provide limiting conditions. All other cases can then be compared with these limiting conditions to see where they fit in the spectrum of viability.

Having taken on board the above considerations, the reservoir simulation team has made a judgment call that the projected recovery from the smaller area (8,000 x 10,000 feet) will likely be at the high end of the realistic per well recovery range and will therefore be used as the “optimistic case”. In practice, a larger area may be drained as there is no physical constraint but discontinuities or areas of poor connectivity may offset this. Overall, for modelling and economics purposes, we will use the projected production from the smaller area as the upper end of expectations. Until proof-of-concept wells are drilled, it is virtually impossible to refine the models further.

For the “breakeven” case, we have used a discounted cash flow internal rate of return (IRR) hurdle rate of 20% reflecting the risks in this play and reverse engineered the production curve accordingly.

5.1 Production profiles

The WellWhiz reservoir simulation model was used to generate production profiles. A volatile oil model was used having been determined to be optimal for recovery and productivity as well as commensurate with the anticipated fluid type at the proposed locations. Various cases were developed for a vertical well with two fracks and a horizontal well with 10 fracks.

When running the models, to speed up convergence times, we have capped maximum daily production from a well at 5,000 barrels per day. To confirm that this was not giving rise to misleading results, we ran one case for a vertical well as a test where initial production was unconstrained. Comparison of the results showed a higher initial production rate in the unconstrained model but an identical cumulative production at the end of 20 years. (Further detail is included in Section 10).

To test the impact of permeability variations we have looked at three scenarios. All three assume homogenous behaviour across the entire layer. In practice, permeability variations will in all probability be localized, but using the macro assumption gives a good indication of the sensitivity of production to this parameter. The scenarios considered use the permeability defined in the input table given in section 4 above for the base case then tests the effect of reducing all permeability by a factor of 10 and a factor of 100.
The final bottom hole pressure is also a consideration. We have used 2,000 psi as the main assumption, but in recognition of the fact that development scenarios may need a higher final bottom hole pressure to allow oil to flow to an FPSO or platform, we have tested the effect of a final bottom hole pressure of 3,000 psi.

Whilst we anticipate the drawdown in the well bore and fracture system will reduce pressure to below the bubble point, we can anticipate that the vast majority of the reservoir matrix will remain above and as such, production will be essentially single phase and we do not expect to see a material increase in the gas production over time.

There is some uncertainty with regards to the PVT data and the Hydrocarbon Densities and the Formation Volume Factor of the nearby Birch field (Hook at al., 2003) were used as a data reference point (Well 16/12a-18).

Key PVT Input data and how it is entered in the simulation model is as follows:

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Density</td>
<td>42-43 API</td>
</tr>
<tr>
<td>Oil Type</td>
<td>Under saturated volatile</td>
</tr>
<tr>
<td>Gas Gravity</td>
<td>0.9 (rel air)</td>
</tr>
<tr>
<td>Viscosity</td>
<td>0.14 cp</td>
</tr>
<tr>
<td>Bubble Point</td>
<td>4,225 psia</td>
</tr>
<tr>
<td>Dew Point</td>
<td>n/a psia</td>
</tr>
<tr>
<td>Gas/Oil Ratio</td>
<td>2,648 SCF/STB</td>
</tr>
<tr>
<td>Condensate Yield</td>
<td>378 Bbl/MMSCF</td>
</tr>
<tr>
<td>Formation Volume Factor</td>
<td>2.4 rb/stb</td>
</tr>
<tr>
<td>Gas Expansion Factor</td>
<td>n/a SCF/RCF</td>
</tr>
</tbody>
</table>
The calculated Oil PVT relationship from the modelling work is as follows:
Where:

\[ rs = \frac{\text{Solution Gas Ratio}}{\text{Gas to Oil Ratio in SCF/STB}} \]

\[ bo = \text{Oil Formation Volume Factor in RB/STB (Oil Flow at Reservoir Conditions/Oil Flow at Stock Tank Barrel Conditions)} \]

\[ \text{viso} = \text{Viscosity of Oil in Centipoise at reservoir temperature} \]

\[ \text{SCF} = \text{Standard Cubic Feet} \]

\[ \text{STB} = \text{Stock Tank Barrel} \]

Relative permeability (Corey Correlation):

Effective permeability of a fluid to some base permeability at a given saturation
Where:

\( \text{kwr} = \text{Relative Permeability, to Water, as a fraction} \)

\( \text{krow} = \text{Relative Permeability, to Oil and Water, as a fraction} \)

\( \text{sw} = \text{Water Saturation, as a fraction} \)

\( \text{krg} = \text{Relative Permeability, to gas, as a fraction} \)

\( \text{krog} = \text{Relative Permeability, to Oil and Gas, as a fraction} \)

\( \text{sl} = \text{Liquid Saturation, as a fraction} \)

As discussed above, the addressed area is a significant variable in the projected production. Two areas were simulated, 8,000 x 10,000 feet and 12,000 x 16,000 feet.
The majority of the cases developed were for single wells, but the final case run was for a typical
development cluster of eight wells. This was run using the “optimistic” case and a “breakeven”
case.

The table below summarizes the production cases run. All the production profiles included
below are detailed in the economic model in graphical and tabular form for ease of reference.

All the cases below assumed an addressed area of 8,000 x 10,000 feet except as noted for cases 8 and 15.

<table>
<thead>
<tr>
<th>Run Reference</th>
<th>Well Type</th>
<th>Bottom Hole Pressure psi</th>
<th>Matrix Permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Vertical</td>
<td>2,000</td>
<td>As per input data table above</td>
</tr>
<tr>
<td>2</td>
<td>Vertical</td>
<td>2,000</td>
<td>Reduced by a factor of 10</td>
</tr>
<tr>
<td>3</td>
<td>Vertical</td>
<td>2,000</td>
<td>Reduced by a factor of 100</td>
</tr>
<tr>
<td>4</td>
<td>Vertical</td>
<td>2,000</td>
<td>As per Case 1 but with daily production cap removed</td>
</tr>
<tr>
<td>5</td>
<td>Vertical</td>
<td>3,000</td>
<td>As per input data table above</td>
</tr>
<tr>
<td>6</td>
<td>Vertical</td>
<td>3,000</td>
<td>Reduced by a factor of 10</td>
</tr>
<tr>
<td>7</td>
<td>Vertical</td>
<td>3,000</td>
<td>Reduced by a factor of 100</td>
</tr>
<tr>
<td>8</td>
<td>Vertical</td>
<td>2,000</td>
<td>As per input data table above, area 12k x 16k feet</td>
</tr>
<tr>
<td>9</td>
<td>Horizontal</td>
<td>2,000</td>
<td>As per input table above</td>
</tr>
<tr>
<td>10</td>
<td>Horizontal</td>
<td>2,000</td>
<td>Reduced by a factor of 10</td>
</tr>
<tr>
<td>11</td>
<td>Horizontal</td>
<td>2,000</td>
<td>Reduced by a factor of 100</td>
</tr>
<tr>
<td>12</td>
<td>Horizontal</td>
<td>3,000</td>
<td>As per input data table above</td>
</tr>
<tr>
<td>13</td>
<td>Horizontal</td>
<td>3,000</td>
<td>Reduced by a factor of 10</td>
</tr>
<tr>
<td>14</td>
<td>Horizontal</td>
<td>3,000</td>
<td>Reduced by a factor of 100</td>
</tr>
<tr>
<td>15</td>
<td>Horizontal</td>
<td>2,000</td>
<td>As per input data table above, area 12k x 16k feet</td>
</tr>
<tr>
<td>16</td>
<td>Horizontal</td>
<td>2,000</td>
<td>Typical 8 well development with FPSO (Base Case &amp; Breakeven)</td>
</tr>
</tbody>
</table>

5.2 Fracture Degradation

Fractures degrade over time and as the pressure in the producing formation drops the frack
relaxes and begins to close. The initial effective permeability of a frack is around 20,000 mD.
The chart below shows the degradation with pressure drop.

In practice, the bottom hole pressure reaches 2,000 psi in the first few days of production so the
frack degrades to the 40% level over the first few days. This is built into the production
simulations.
5.3 Impact of restrained versus unrestrained initial production rate

As discussed above, the initial production rate for all wells was limited to 5,000 barrels per day to speed up model convergence. To confirm that this is not distorting results detrimentally, a pair of cases was run (Cases 1 and 4) to compare the daily production curves and the 20 year cumulative totals. The results of this comparison are shown below.

As can be seen, the 20 year cumulative totals are identical. The unrestrained cases gives a higher initial daily production rate but daily rates converge after 2 years. The constrained case is therefore a more conservative approach.
5.4 Vertical well results for cases 1 to 3

**Vertical well – oil production rate / cumulative oil production**

**VERTICAL WELL COMPARISONS**

**AVERAGE DAILY OIL PRODUCTION RATES**

<table>
<thead>
<tr>
<th>Year</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
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<tr>
<td>15</td>
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</tr>
</tbody>
</table>

**VERTICAL WELL CASES, 2,000psi BHP**

(10,000 x 8,000 ft area, 37.4 Mmbbls STOIIP)

**Case 1:**
Permeability as per input table (0.2 – 30 mD)

**Case 2:**
Permeability reduced by a factor of 10

**Case 3:**
Permeability reduced by a factor of 100

**Case 1:**
- Oil Recovery After 20 Years: 7.79 Mmbbls
- Implied Recovery Factor: 20.80%
- Initial Oil Flow Rate: 5,000 BPD
- Oil Flow Rate After 5 Years: 1,327 BPD

**Case 2:**
- Oil Recovery After 20 Years: 7.79 Mmbbls
- Implied Recovery Factor: 20.80%
- Initial Oil Flow Rate: 5,000 BPD
- Oil Flow Rate After 5 Years: 1,327 BPD

**Case 3:**
- Oil Recovery After 20 Years: 7.79 Mmbbls
- Implied Recovery Factor: 20.80%
- Initial Oil Flow Rate: 5,000 BPD
- Oil Flow Rate After 5 Years: 1,327 BPD

**Vertical well – gas production rate / cumulative gas production**

**VERTICAL WELL COMPARISONS**

**AVERAGE DAILY GAS PRODUCTION RATES**

<table>
<thead>
<tr>
<th>Year</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
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<td></td>
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<tr>
<td>2</td>
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<td>7</td>
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<tr>
<td>10</td>
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<tr>
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<td>13</td>
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<td></td>
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<tr>
<td>14</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**VERTICAL WELL COMPARISON**

**CUMULATIVE GAS PRODUCTION**

**Case 1:**
- Gas Recovery After 20 Years: 10.84 BCF
- Initial Gas Flow Rate: 6.61 MMSCFD
- Gas Flow Rate After 5 Years: 1.87 MMSCFD
- Water Recovery After 20 Years: 475 Bbls

**Case 2:**
- Gas Recovery After 20 Years: 10.84 BCF
- Initial Gas Flow Rate: 6.61 MMSCFD
- Gas Flow Rate After 5 Years: 1.87 MMSCFD
- Water Recovery After 20 Years: 475 Bbls

**Case 3:**
- Gas Recovery After 20 Years: 10.84 BCF
- Initial Gas Flow Rate: 6.61 MMSCFD
- Gas Flow Rate After 5 Years: 1.87 MMSCFD
- Water Recovery After 20 Years: 475 Bbls
5.5 Horizontal well results for cases 9 to 11

Horizontal well – oil production rates / cumulative oil production

HORIZONTAL WELL CASES, 2,000psi BHP
(10,000 x 8,000 ft area, 37.4 Mmbbls STOIIP)

Case 9:
Permeability as per input table (0.2 – 30mD)

Case 10:
Permeability reduced by a factor of 10

Case 11:
Permeability reduced by a factor of 100

Horizontal well – gas production rates / cumulative gas production

Case 9:
Gas recovery After 20 Years: 13.4 BCF
Initial Gas Flow Rate: 6.61 MMSCFD
Gas Flow Rate After 5 Years: 2.66 MMSCFD
Water Recovery After 20 Years: 513 Bbls
5.6 Summary of all production cases

<table>
<thead>
<tr>
<th>Case #</th>
<th>Well Type</th>
<th>Perm Md</th>
<th>BHP psi</th>
<th>Area (ft)</th>
<th>Initial Prod Capped at 5,000 bpd</th>
<th>Oil Cum MMBbbls 20 Years</th>
<th>Oil Production Bpd Initial/ After 5 Yrs</th>
<th>Gas Cum BCF 20 Years</th>
<th>Gas Production MMSCF/D Initial/ After 5 Yrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 (Vert)</td>
<td>Base</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>7.79</td>
<td>5,000/1,327</td>
<td>10.64</td>
<td>6.61</td>
<td>1.66</td>
</tr>
<tr>
<td>2 (Vert)</td>
<td>Base/10</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>3.75</td>
<td>2,794/609</td>
<td>4.81</td>
<td>3.54</td>
<td>0.79</td>
</tr>
<tr>
<td>3 (Vert)</td>
<td>Base/100</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>1.12</td>
<td>667/176</td>
<td>1.48</td>
<td>0.50</td>
<td>0.23</td>
</tr>
<tr>
<td>4 (Vert)</td>
<td>Base</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>No</td>
<td>7.79</td>
<td>12,707/1,266</td>
<td>10.65</td>
<td>15.71</td>
<td>1.79</td>
</tr>
<tr>
<td>5 (Vert)</td>
<td>Base</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>6.22</td>
<td>3,952/1,059</td>
<td>6.71</td>
<td>4.03</td>
<td>1.15</td>
</tr>
<tr>
<td>6 (Vert)</td>
<td>Base/10</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>3.20</td>
<td>2,391/637</td>
<td>3.13</td>
<td>2.30</td>
<td>0.52</td>
</tr>
<tr>
<td>7 (Vert)</td>
<td>Base/100</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>0.93</td>
<td>553/146</td>
<td>1.24</td>
<td>0.43</td>
<td>0.20</td>
</tr>
<tr>
<td>8 (Vert)</td>
<td>Base</td>
<td>2,000</td>
<td>12k x 10k</td>
<td>Yes</td>
<td>17.20</td>
<td>5000/4,807</td>
<td>23.93</td>
<td>6.61</td>
<td>5.74</td>
</tr>
<tr>
<td>9 (Hor)</td>
<td>Base</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>6.42</td>
<td>5,000/1,733</td>
<td>12.5</td>
<td>6.61</td>
<td>2.66</td>
</tr>
<tr>
<td>10 (Hor)</td>
<td>Base/10</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>4.53</td>
<td>2,405/646</td>
<td>6.09</td>
<td>2.33</td>
<td>1.16</td>
</tr>
<tr>
<td>11 (Hor)</td>
<td>Base/100</td>
<td>2,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>2.09</td>
<td>1,441/434</td>
<td>3.03</td>
<td>1.08</td>
<td>0.57</td>
</tr>
<tr>
<td>12 (Hor)</td>
<td>Base</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>7.81</td>
<td>5,000/1,564</td>
<td>8.29</td>
<td>6.61</td>
<td>1.59</td>
</tr>
<tr>
<td>13 (Hor)</td>
<td>Base/10</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>3.86</td>
<td>2,407/761</td>
<td>6.12</td>
<td>2.93</td>
<td>1.06</td>
</tr>
<tr>
<td>14 (Hor)</td>
<td>Base/100</td>
<td>3,000</td>
<td>8k x 10k</td>
<td>Yes</td>
<td>2.31</td>
<td>1,673/388</td>
<td>2.94</td>
<td>1.37</td>
<td>0.41</td>
</tr>
<tr>
<td>15 (Hor)</td>
<td>Base</td>
<td>2,000</td>
<td>12k x 10k</td>
<td>Yes</td>
<td>21.4</td>
<td>5,000/5,000</td>
<td>30.4</td>
<td>6.51</td>
<td>6.61</td>
</tr>
<tr>
<td>16 (Hor)</td>
<td>Base</td>
<td>2,000</td>
<td>64k x 80k</td>
<td>Yes</td>
<td>75.34</td>
<td>40,000/14,106</td>
<td>108.3</td>
<td>52.88</td>
<td>21.31</td>
</tr>
</tbody>
</table>

Of particular note is the cumulative oil production for Case 1, Vertical Well, at 7.79 million barrels and Case 9, Horizontal Well, at 9.42 million barrels. The relatively small improvement in cumulative production (21%) for a 60% increase in the well cost suggests that horizontal wells are economically questionable. However, we need to remember that the models are assuming homogenous layers whereas this may not be entirely so. Multiple fracks increase the likelihood of achieving higher cumulative production. The North American experience also suggests that substantial enhancements occur in production rates with time as knowledge is gained on how best to drill and complete horizontal wells. A view on this can be taken after the vertical “proof of concept” well has been drilled and tested. Data so gleaned will drive the forward programme.

1. Economic modelling

An economic model was created. However, given the vagaries of most of the input parameter assumptions the results are not included in this report. The modelling was based upon a project development workflow described as follows:

7. Project Development Workflow

7.1 Drill vertical well at predefined location for purpose of adding control points for layer definitions in the 16-12b-6 well and, if ultimately undertaken, the first manifold, 8-well development plan. Control point acquisition will be designed to ensure that enough of an area and reserves can be accessed with the vertical well to support tying it back to South Brae (or other appropriate infrastructure).
a. Core, log and test.
b. Carry out two fracks, the first covering layers 6 through 14 through perforation at top of Layer 13 and the second covering layers 1 through 5 through a perforation at the top of Layer 5.
c. Short-term flow test.
d. If flow-test is positive, suspend well for tie back to South Brae, if not, plug and abandon.

7.2 If results of 15.1 are positive, drill a horizontal well with a 5,000 ft. lateral. Locate the well at a position to get a third control point on the layer definitions in the 16/12b-6 well and potential first manifold, 8-well tie back program.

a. Horizontal section will probably enter Layer 1 at an angle of 7° to the horizontal then penetrate all layers. Details to be defined after completion of 15.1.
b. Institute 10-frack program (6 small top fracks and 4 large bottom fracks).
c. Tie well back to South Brae (or other appropriate infrastructure), through same flow line as vertical well, assuming vertical well was tied back.
d. Flow test well for 1 year.

7.3 Commence 1st manifold development plan.

a. Drill and suspend seven 5,000 ft lateral wells
b. Frack all seven wells.
c. Tie seven new wells and the initial vertical and horizontal wells (assuming they are still producing at an economic rate) back to an FPSO.
d. Wait one year to gather production data from the horizontal wells, particularly the decline curves

7.4 After one year of production from the wells in point 15.3 are on production:

a. Drill, core, log and suspend three additional vertical appraisal wells at locations that would correspond to development areas for manifold clusters 2 through 4.

7.5 With two rigs, drill seven 5,000 ft. horizontal wells around manifold 2 and re-enter, plug back and drill a 5,000 horizontal lateral in the manifold 2 vertical well.

a. Frack 8 wells drilled in manifold 2 area.
b. Tieback 8 wells to FPSO.
c. For the FPSO, we will need to decide if we are leasing, buying or leasing with an option to buy (lease purchase option). The economics have assumed a leased FPSO, as that will in all probability be the most expensive but also most flexible option. The lease or buy decision can be made when the need for the FPSO materializes and will be based on the market conditions of the day. We need to bear in mind that an FPSO for a development such as this would be quite different from a conventional development. For a start, there would be no need for water injection and the power generation would be significantly reduced as a consequence. There would be no need for gas lift and again, this reduces the complexity BUT this does mean that the FPSO would have a limited market upon completion of this development.
7.6 On a continuous basis repeat step 15.5 for manifold 3 and 4 areas.

8. Clearance

Trap Oil Ltd confirms that DECC is clear to publish this relinquishment report.

9. References cited
