Fairfield Cedrus Limited

UKCS Licence P110 & P591
Block 16/29a and Blocks 16/29b & 16/24b

Relinquishment Report

July 2015
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1. Licence Information

<table>
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2. Licence Synopsis

Licence P110, Block 16/29 (Figure 2.1), was originally awarded to a group led by Phillips Petroleum in the Third UKCS Licensing Round (1970). A closed, domal structure was evident even on the seismic of the day and led to the discovery of the Maureen field by well 16/29-1 in 1972 with the field coming on stream in 1983.

From first production to 2004 there were ten changes of licencee in P110, the final equity owners being BG, Centrica, ConocoPhillips and Total. In 2004 the Centrica, ConocoPhillips and Total equity was purchased jointly by Apache (Operator) and Acorn Oil & Gas. Fairfield acquired Acorn’s interest on its foundation in November 2005.

Following the unsuccessful drilling of two wells (and two failed attempts at reaching a third, Fairfield favoured, target) in 2006/07, Fairfield Cedrus Limited, a wholly-owned subsidiary of Fairfield Energy, signed a Sale and Purchase Agreement with Apache North Sea Ltd. to purchase its interests in the Greater Maureen Area. On completion of that deal, Fairfield assumed 100% equity holding in Licences P110, P1173 and P1174 (P1173 and P1174 were awarded to the Apache/Fairfield JV in the 22nd UKCS Licensing Round and were relinquished by Fairfield in December 2008) and an 81.14% interest in Licence P591 (with Eni holding 18.86%).

In 2009, Fairfield Cedrus Limited farmed out 38.46% of Licence P110 to Endeavour Energy in return for a carry on the drilling of a well to appraise the third target of the 2006/07 Apache Operated drilling campaign. Despite encountering high quality reservoir sands, the top of the Palaeocene Maureen Sandstone Fm. came in quite deep to prognosis resulting in excessive proximity to the original OWC and the presence of only swept sandstones.

The Second Term for Licence P110 expires on the 8th June 2016.
3. Work Programme Summary

The original P110 licence work programme comprised ‘carrying out seismic survey work in the licensed area and drill therein at least two exploration wells’. This programme has clearly been completed through the exploration, appraisal and development of the Maureen Field, along with the Mary and Morag fields which also lie within the licence area, involving 29 wells and 9 separate 2D/3D seismic surveys (excluding various re-processing studies).

4. Database

4.1 Seismic

Following award of licence P110 to ConocoPhillips in 1970, 135km of seismic data were acquired (Phillips Survey PS16/29 – 5 lines acquired in each of north-south and east-west orientations) and subsequent mapping indicated a closure at top Palaeocene level of 27.7km².
with vertical relief of 600ft (183m). Revised interpretations following the acquisition of 132km of infill seismic data in 1973 (Phillips Survey PW16/29 – resulting in a 1.6km grid) suggested the structure was a more narrowly elongated dome than in the original mapping with a distinctly smaller closed area but the same vertical relief.

In 1978, a further 107km of seismic data were acquired (Phillips Survey PF16/17) and following submittal of the Annex B in December of that year, 370km of new 2D seismic data were acquired in 1981 (Phillips Survey P-8102) which led to a revised structure map which increased STOIIP estimates slightly over those calculated after the 1973 mapping.

In 1984, 410km of seismic data were acquired (Phillips Survey PD-842) and interpretation of this dataset resulted in a significant increase (~90MMbbls) in STOIIP estimates. In 1985, 390km of new seismic data were acquired (Phillips Survey PD-851) and combined with reprocessing of the 1981 2D seismic, a new structure map was derived from which the STOIIP and reserves were calculated to be substantially higher than envisaged at the time of Annex B submission and so regulations required a formal revision.

In 1988, 366km2 of 2D seismic data were acquired (Phillips Survey PS-882). During 1990, the 1981, 1985 and 1988 seismic data were reprocessed into a pseudo 3D volume over the Morag field. In 1994 a 3D seismic survey was acquired over the field (Phillips Survey TQSVG), as part of a larger survey being taken in blocks 16/24 and 16/23, and in 1995 Phillips applied a proprietary inversion technique to the 3D data to create a 3D porosity data volume over Maureen.

The Maureen field area had a new 3D seismic dataset shot over it in 2004 and 2005. The data were acquired by Veritas DG C Ltd as part of their long-offset Q15 and Q22 surveys. The data used for the bulk of the structural interpretation had been processed through pre-stack time migration. Full, near and far offset amplitude data were used (Figure 4.1). Coloured and simultaneous inversion data were also used where appropriate. It should be noted that because of mismatches with the 1994 undershoot 3D it was not possible to use 4D techniques with these data.

### 4.2 Wells

Prior to 2006, twenty nine wells had penetrated the Palaeocene sandstones in the Maureen field. Of these, 4 were exploration wells and the rest a mix of producers/injectors with many producers later being re-completed as injectors. Table 4.1 summarises the general information for each of these wells.
Figure 4.1 Maureen field 2004/5 3D seismic data

Table 4.1 Maureen well data summary

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P.110
In late 2006/early 2007, Apache North Sea Ltd. (61.2% & Operator) and Fairfield Cedrus Ltd. (38.8%) drilled a 3 legged ‘spider’ well on the Maureen field to appraise the remaining hydrocarbon potential of the Palaeocene Maureen Formation reservoir, in the abandoned Maureen Field. This involved drilling and casing a shared 12 ¼” hole section down to 954m and then drilling 8 ½” openhole legs to three targets (Figure 4.2).

- North West Maureen (NWM – defined on the basis of seismic inversion and analogous to Apache’s experience on Forties),
- North Maureen (NOM defined on the basis of Apache’s reservoir simulation alone)
- North East Maureen (NEM defined on the basis of seismic inversion and reservoir simulation).

NWM (16/29a-16A) and NOM (16/29a-16Z) were tested by the drilling programme but both encountered swept reservoir save for 2m of remaining oil pay at the top of the NOM well. The NEM target (16/29a-16Y) was unable to be tested due to drilling difficulties, encountered at 2709m, which led to the abandonment of this well section and another sidetrack (16/29a-16X) being kicked off from 1643.5m in an attempt to reach the NEM target. This was also unsuccessful, encountering drilling difficulties at a very similar position within the overburden. The tophole section was then plugged and abandoned.

Given that the 2006/07 appraisal programme had failed to prove the validity of the seismic inversion ‘fluid indicator’ attributes, Fairfield acquired Apache's interest and operatorship later that year. With NEM having always been Fairfield's preferred target, in 2009 a farm out deal was completed with Endeavour Energy and Challenger Minerals with Endeavour Energy taking 38.46% equity in the licence in return for funding the drilling of the NEM target (upon completion of the well, Challenger Minerals elected not to take up the working interest in the licence that had been earned).

Well 16/29a-17 (eastern red spot on Figure 4.3) was operated by Fairfield Energy and drilled, under a Turnkey contract with ADTI, and had been designed to test the potential for remnant, unswept oil lying in the North East portion of the abandoned Maureen Field. Spudded on the 7th August 2009, the well was drilled to TD within 14 days. Top Maureen main sand was encountered 111 ft TVD deep to prognosis while top Ekofisk (effective base Maureen) came in only 26 feet deep. The Maureen sand was not only thinner than forecast but was significantly closer to the original oil water contact (-8690ft TVDSS) resulting in only remnant hydrocarbon saturations being encountered. The well was therefore plugged and abandoned on 23rd August 2009.
4.3 Production

4.3.1 Maureen Field

The Maureen field (Figure 4.3) is an oil accumulation reservoired principally within Palaeocene age sandstones at the crest of an antiform formed in response to localised halokinesis within the Zechstein salts. The salts have not yet formed a true diaper, causing only doming within the overburden stratigraphy. Exact timing of the halokinesis is uncertain but early movements were contemporaneous with Palaeocene sediment deposition, evident from the distribution and stacking patterns of the individual Maureen fan sandstones across the structure.

The first exploration well (16/29-1) was drilled in 1972 and encountered hydrocarbon bearing sandstone at the Palaeocene level. Following the acquisition of further seismic the first appraisal well (16/29-2) was drilled NW of the discovery well with a second one soon to follow,
4km north of the discovery well, in 1974. Significant study work was performed prior to the drilling of the third appraisal well which aimed to test uncertainties in the reservoir distribution to the NE of the field. Doubts about the commerciality of the field due to thinning sands over the crest and a dry development on the Cod Field meant Maureen was in danger of not being developed. However, in June 1978 a draft Annex B was submitted to the Department of Energy which presented Maureen as an essentially unfaulted dome shaped closure elongated NW-SE. STOIIP volumes in the draft Annex B used an OWC of -8652ft TVDSS (chosen at the 60% Sw depth in well 16/29-2) although models had been made using the actual OWC at -8683ft TVDSS. For the final Annex B submitted in December 1978, the deeper OWC was used which gave a STOIIP of 288.6MMbbls at that time.

In June 1979, an integrated platform with a 24 slot template was installed and development drilling on Maureen commenced later that same month. By early 1982, 10 producers and one injector had been drilled. Revised mapping resulted in a STOIIP increase and the realisation that locations previously chosen for three of the still undrilled water injectors were not ideal. These locations lay along the eastern flank of the field where the reservoir was observed to thin meaning the wells would not penetrate all geological layers and the amount of sand would be insufficient to achieve the required injectivity. By July 1983, 12 producers had been drilled, one intended producer (16/29a-A12) having been abandoned after a gas kick in the upper Tertiary. Water injectors had also been drilled although 16/29a-A15 had encountered an anomalously sand poor reservoir and was not used for injection.

On September 14th 1983, the Maureen field came on stream through two wells (16/29a-A6 and 16/29a-A4) with the remaining producers not being hooked up until April 1984. On February 25th 1984 peripheral water injection started in well 16/29a-A10. By 1984 all wells were on stream (the last one being 16/29a-A13) and production averaged 73 500 BOPD with peak production of 102 000 BOPD in May 1984. Plateau production of 80 000 BOPD (limit of system design) was maintained until 1987 when it began to decline.

From 1984 gas lift began being installed and the re-processing of the seismic data resulted in a STOIIP increase to 393.2MMbbls (substantially higher than was envisaged at the time of Annex B submission and so regulations required a formal revision). The early dynamic model had predicted water breakthrough much earlier than had actually occurred and new studies suggested an increases in recoverable reserves to 207.7MMbbls

By December 1989 the field was producing 60 000 BWPD and 50 000 BOPD. Static pressure measurements taken in 1990 suggested voidage replacement was occurring through injection and aquifer influx. By December of 1998, 80% of water injection was produced water.
In January 1999, the field was abandoned having produced 216.3MMbbls of oil (RF of 55%) and 146.3MMbbls water. Water injection totalled 285.9MMbbls of which 194.4MMbbls was sea water and 91.4MMbbls produced water.

![Maureen field map](image)

_Figure 4.3 Maureen field map (white contour shows the OWC, blue spots are injectors, green spots are producers (all final well classification) and red spots are post development exploration wells drilled by Apache/Fairfield & Fairfield/Endeavour._
4.3.2 Mary Field

The Mary field is an oil accumulation reseroired within Upper Jurassic, Hugin Formation sandstones deposited in a palaeotopographic low on the NNE flank of the Main Maureen structure (Figure 4.4). The field is located 1.5km NE of A1 and was discovered and brought on stream in 1991. Three further wells were drilled into the Mary structure although only one was successful. By the end of November 1998, the reservoir had produced 2.37MMbbls with most of the production coming from the horizontal well 16/29a-A25. Rapid decline from that point, mainly owing to a lack of pressure support (static pressure measurements in April 1999 showed a pressure of 822psi). A25 produced 1.85MMbbls of oil from the Mary field’s 2.5mmbbl total recoverable volume.

Figure 4.4 Top Zechstein surface with top Hugin Formation (Top Mary Field) displayed showing the limited sand distribution within a palaeolow on the Zechstein topography (eastern flank of the Maureen field).
4.3.3 Morag Field

The Morag field was discovered in 1979 when drilling the first of the Maureen development wells (16/29a-A1). It lies directly beneath the Main Maureen field, at Zechstein level (Figure 4.5), and was developed with this single well which was recompleted as a Zechstein producer later in field life after the Palaeocene interval in the well had reached high water cut. In 1994 the Morag field was shut in as the reservoir pressure fell to 903psi.

The reservoir, a series of dolomite slabs (production is also reported from the underlying anhydrite), resulted from the break-up of a late Permian dolomite layer during halokinesis within the Zechstein salt. This culminated in the deformation of the overburden which in turn caused the formation of the overlying antiform, the structure which forms the trap for the Maureen field (Figure 4.3).

Figure 4.5 Morag field depth structure map. Wells 1X, A1, A2 & A23 proved mobile petroleum, wells A3 & A6 penetrated non-reservoir anhydrite.
5. Prospectivity Update

5.1 Prospect Description

Licences P110 & P591 (blocks 16/29a, 16/29b and 16/24b) contain significant prospectivity across multiple stratigraphic levels. Although many of the opportunities are fairly modest in scale, there is opportunity to comingle meaning they represent a potentially more material portfolio when combined with an appropriate catalyst.

The key prospects identified (see Figure 5.1) are:

- Re-saturation of the Maureen Field itself
- Re-development of Morag A23
- Small near field discoveries (2X, Elk)
- Near field exploration (JR1, TR1, Boar) – Mary analogue

![Figure 5.1 Maureen area prospectivity](image)
5.2 Maureen Re-saturation

The Palaeocene Maureen Formation was in production until 1999. Total production from the field was 217 MMstb, which represents a recovery factor of 58% assuming a STOIIP of 400 MMstb. Produced oil was light with a gravity of 36 API, Gas Oil Ratio (GOR) of 392 scf/stb and viscosity lower than 1 cp.

Based on experience of the Dunlin field, Fairfield considers that there could still be remaining waterflood mobile oil in the Maureen Attic owing to re-saturation, or re-segregation, with similar phenomenon having been observed in analogue fields such as Angus, Piper etc. CO₂ sequestration studies, performed on Maureen through 2011-2012 by Progressive Energy, have also gone some way to assessing the feasibility of an EOR programme injecting carbon dioxide.

Investigation into the scale of the potential was initially completed through an analytical based approach via decline analysis of the historical data, using water oil ratio versus cumulative water injection and water oil ratio versus cumulative production. A trend based on the historical water injection and water oil ratio was defined, shown in Figure 5.2, since it is considered that even if re-saturation occurs, it is likely that the last historical trend will be maintained although the phenomenon should account for slightly lower WORs being chosen.

An outline development concept based on the re-segregation concept includes 3 producers (twins of existing wells A7, A4, A24Y) and 2 new water injectors, with 100% voidage replacement. Further appraisal drilling and logging on the field would be required to prove the re-saturation/re-segregation concept and mitigate some of the current risks before committing to a full redevelopment.

In order to generate outline profiles for such a redevelopment, a dynamic model of the field was history-matched to the original field development and adjusted to predict re-saturation of attic locations. Initial simulation work was based on the proposition that the current commercial software may under-predict the rate of re-saturation and that it may be happening much faster than is being modelled. Therefore, sensitivity cases, assuming 500 and 1000 years of re-saturation (shut in), were run to investigate the maximum potential although these are considered to reflect a very high case.

More recent simulation efforts have focussed on ascertaining the true controls on the rates of re-saturation and the robustness of the simulator in terms of the effects of the model construction. These have suggested that the model is accurate and so the low and base cases have been modelled under normal re-segregation timing over the approximate 20 years of shut in since CoP, assuming production re-start in 2020 (see Figure 5.3).
Figure 5.2 Maureen WOR vs cumulative oil showing pessimistic low, mid and high case scenarios (as they assume no lowering of the WOR which should be expected given the 20 year period of re-saturation).

Figure 5.3 Oil/Water re-segregation in dynamic model over 20 year period
5.3 Morag

The reservoir comprises a series of dolomite slabs (production is also reported from the underlying anhydrite), resulted from the break-up of a late Permian dolomite layer during halokinesis within the Zechstein salt (Figure 5.4). This culminated in the deformation of the overburden which in turn caused the formation of the overlying antiform, the structure which forms the trap for the Maureen field. The greatest thickness of reservoir was encountered at the crest of the structure where extensive fracturing has significantly improved reservoir quality.

Several wells have penetrated the Zechstein dolomite under the Maureen field but only three have encountered hydrocarbons. The A1 well penetrated a double-thickness of Zechstein dolomite and was completed as a producer, producing 2.65MMbbls over the well's life. The A23 well also encountered hydrocarbons at or near original reservoir pressure (evident from the drilling problems and scale of the kick encountered) suggesting a disconnection with the A1 slab. The well was abandoned without completion (owing to the drilling problems) and represents a target with a 100% chance of encountering hydrocarbons. It was considered that this target could be considered an add-on to a Maureen Sand appraisal well/producer with a single well able to be drilled through both the potentially re-saturated Maureen Sandstone and into the deeper Morag target.

Figure 5.4 Play concept for the Morag Zechstein play
5.4 Small, Near Field Discoveries (2X, Elk)

The 2X discovery is a Triassic Skagerrak sandstone onlapping the Maureen salt dome in the WNW area of the structure (see figure 5.1). The structure is dip-closed to the west with updip fault seal and possible pinchout to the east against the Maureen salt diapir. The discovery well (16/29-2) encountered good porosity Skagerrak sands and tested hydrocarbon from three separate zones. The top test flowed 750 bopd of 38 API oil, the second and third tests flowed, very little, 39 and 38 API oil respectively (see Figure 5.5). The tested intervals are separated by carbonate cemented sands. The size of the accumulation is poorly constrained with the position of the OWC being a key variable used in the STOIIP evaluation.

![Figure 5.5 16/29-2 CPI showing the Triassic section and the three tested hydrocarbon bearing zones.](image)

The Elk prospect targets Jurassic Hugin sandstones onlapping the western margin of the Maureen salt dome (figure 5.1), downdip of well 16/29a-A6. Seismic mapping indicates the possibility of Hugin sandstones thickening slightly to the West in this area (see figure 5.6) although absolute Hugin thickness is uncertain but is projected to be limited. The updip seal is against the salt while the overlying seal is expected to be from the Mid-Upper Jurassic shales and volcanics of the Heather/Kimmeridge Clay and Rattray Fms (analogous to the Mary field which is also a Hugin Sandstone on the NE flank of the structure).
Well A6 (slightly to the east of the Elk prospect) encountered Pentland sands (tested at 450bopd) which may, or may not, actually be Hugin sands. If Pentland sands, their extent is likely to be even more limited and would certainly limit any potential for upside on the prospect.

5.5 Near Field Exploration (JR1, TR1)

The JR1 prospect is analogous to the Elk and Mary fields in that it is mapped as a Hugin sandstone onlapping the Maureen salt dome in the northwest area of the structure (see figure 5.1). Well 16/29-3 (Figure 5.7), penetrating down dip of the potential prospect, encountered good porosity Hugin sands although they were water bearing, flowing 4000BWPD on test with a trace of gas. The updip seal for the JR1 prospect is mapped as a significant fault.

Not surprisingly, the risk associated with the JR1 prospect is large owing to the uncertainty around the thickness/extent of Hugin sandstone (especially considering the learnings made from examining the extent of the Mary field) combined with additional concern over whether or not it has been charged by hydrocarbon in this area.
The TR1 prospect is a Triassic Skagerrak sandstone onlapping the Maureen salt dome in the northwest area of the structure (see figure 5.1) underlying the JR1 prospect. Well 16/29-3 also encountered good porosity Skagerrak sands (below 10630ft), with shows (figure 5.7), although they were water bearing, testing 2000 bwpd from DST #2. The updip seal for the TR1 prospect is the same significant fault that is mapped to trap the stratigraphically younger Jurassic Hugin sands of the JR1 prospect.

Much like the JR1 prospect, the key risk is the distribution and continuity of the Skagerrak sandstone and the issue of whether or not there has been a phase of hydrocarbon charge. Well 16/29-2 flowed oil from the Triassic on test (figure 5.5, DST #3 produced 750 bopd, 38° API) and so the potential has been proven nearby at this level.

Low and high STOIIP variance in both these prospects is primarily a result of the different polygon outlines used to define the potential extent of the individual sandstones updip of the 16/29-3. Many of the other specific inputs have been derived from the analogous Mary field, in the case of JR1, and the 16/29-2 well in the case of TR1.
6.0 Further Technical Work Undertaken

Following the lack of success during the 2009 drilling at NEM, a successful re-development of Maureen looked difficult (with sizeable reserves at Maureen required to unlock the additional potential in Morag etc). During the following two years, Fairfield worked closely with both Durham University and Progressive Energy to assess the viability of using Maureen for carbon capture and storage although this was ultimately unsuccessful. Around that time, Fairfield had significant success, at one if it’s other assets, as a result of re-saturation of oil. In considering the potential for this phenomenon at Maureen, the results were very encouraging and triggered a thorough re-assessment of Maureen from the ground up in collaboration with RPS in Winfrith. The seismic interpretation and velocity model were brought up to date using the new wells and a revised static model was built incorporating all the observations from the extra well penetrations (specifically those at NEM). The culmination of this work was support for the analytical assessment which had suggested there could be sizeable potential however the seismic mapping suggested the distribution of the re-saturated oil may be more widespread than had been modelled previously. This is primarily a result of two distinct crests at the top of the Maureen structure both at the same depth, as oppose to only one crest mapped originally. At the same time, Fairfield have considered various novel development solutions (UPB) but none have been found to be economically viable given the expected production profiles and the significant well count required to reach the mid case reserves shown below.

7.0 Resource and Risk Summary

<table>
<thead>
<tr>
<th>Prospect</th>
<th>Reserves/Resources</th>
<th>Chance of Success</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low</td>
<td>Mid</td>
</tr>
<tr>
<td>Maureen Re-saturation</td>
<td>9</td>
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<tr>
<td>Morag A23</td>
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<td>0.2</td>
</tr>
<tr>
<td>2X</td>
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</tr>
<tr>
<td>TR1</td>
<td>0.2</td>
<td>0.9</td>
</tr>
</tbody>
</table>

* these are technical reserves and the well count associated with this case is prohibitive. Figure 5.2 presents a more viable analytical mid case of around 13mmbbls which is underpinned by the 3 producer, 2 injector simulated case discussed in section 5.2
8.0 Conclusion

Although the most recent technical assessment suggests there is the potential for reasonable reserves on Maureen, the revised seismic mapping and updated static model suggest the need for an increased well count and/or a decrease in the effective oil rate. Both these elements culminate in a significant reduction in the economic attractiveness of a potential Maureen field re-development at this time.

9.0 Clearance

Fairfield Cedrus confirm that the Department of Energy and Climate Change is free to publish the contents of this report and that all third party ownership rights (on any contained data and/or interpretations) have been considered and appropriately cleared for publication purposes.