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The Development of Heavy Oil Fields in the U.K. Continental Shelf: Past, Present and Future

A J Jayasekera, SPE, United Kingdom Department of Trade and Industry, S G Goodyear, SPE, AEA Technology

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Abstract

Historically, most UKCS production has been of light oil, 30° API and above. However, since 1993, a number of heavy oil fields have been brought on production. This paper reviews the history of UKCS heavy oil, the challenges overcome to bring these fields to development, and the future outlook.

The occurrence and distribution of the UKCS heavy oil in place is discussed. A specific correlation to estimate reservoir viscosity from API gravity is presented. Productivity of heavy oil reservoirs is compared with light oil developments, different categories of heavy oil reservoirs are identified, and the use of horizontal or multilateral well technology to achieve acceptable production rates is discussed. The implication of well productivity testing (e.g. extended well testing) of appraisal wells is discussed.

The development challenges that have been overcome in current developments (Harding, Gryphon, Alba, Captain) are reviewed, in particular focusing on well productivity, pressure support, recovery efficiency (management of gas and water coning, areal sweep), and oil water separation. The paper will also review the cost and risk management strategies that need to be adopted to enable the economic exploitation of these heavy oil resources in a demanding environment such as the UKCS.

Finally, the potential for future heavy oil developments is discussed. The scope for IOR technology to increase reserves in heavy oil fields on production by waterflood, or to improve the economics of currently sub-economic fields, is reviewed, focusing on advanced well technology, downhole separation, thermal techniques and conformance control methods.

Introduction

Early production from UKCS oil fields has been of light oil. However, a significant number of “heavy” oil fields have also been discovered, which, in the context of this paper, is taken to refer to reservoirs with in-situ viscosities greater than 5 cp. The majority of UKCS heavy oil occurs in relatively shallow reservoirs, comprising high porosity unconsolidated sands with excellent horizontal permeability (typically 3,000 to 10,000 md) and very high vertical permeability ($k_v:k_h$ in the range 0.2 to 1.0). The oil columns are usually at least partially underlain by water and some also have primary gas caps.

This combination of reservoir parameters and the demanding offshore environment of the UKCS, presents a special set of reservoir engineering challenges, because of the difficulties in achieving and maintaining sufficiently high production rates to justify development. This paper provides an overview of the development of heavy oil fields on the UKCS, past, present and future, with an emphasis on the sub-surface issues. This shows how the application of new technology, principally horizontal wells, extended reach drilling and improvements in sand control has led to successful developments. Increasing confidence in this technology has allowed the Captain field (reservoir viscosity 88 cp) to be brought on to production and encouraged appraisal activity on other fields with viscosities as high as 1000 cp.

It is conservatively estimated that there are around 10 billion STB of heavy oil in place on the UKCS. Less than a quarter of this resource is currently being developed. Assuming that recovery factors for the undeveloped STOIP are likely to be in the range 20 to 40 %, shows that there are approximately 1.5 to 3 billion barrels of additional reserves to be produced, which will make a significant contribution to the longevity of the UKCS.

Heavy Oil Resources in the UKCS

Heavy oil production first took place on the UK mainland in the late 18th century. This was in Ironbridge, Shropshire, where heavy oil from the Carboniferous was produced through seepage into mine shafts. With the onset of oil exploration in the North Sea it was inevitable that some oils that fall into the heavy oil category, would be discovered. Many of the heavy oil accumulations discovered in the UKCS are in the Northern

North Sea, in the eastern margins of the East Shetland Platform. Other significant discoveries are in the Fladen Ground Spur, the Halibut Horst, and west of the Central Graben. Heavy oils have also been discovered in the Atlantic margin area. **Fig. 1** shows the structural elements in the Central and Northern North Sea and the location of producing heavy oil fields and those currently being actively appraised.

The majority of heavy oil discovered to date occurs in the Lower Tertiary. **Fig. 2** shows the conceptual chronostratigraphy of the important Lower Tertiary sand reservoirs. The main heavy oil reservoirs are in the Upper Palaeocene Maureen Formation, the Heimdal sands in the Lista formation (e.g. Mariner), and the Dornach and Hermod sands in the Sele formation (e.g. Bressay), the Balder and Frigg sands (e.g. Gryphon and Harding) and the mid-Eocene Nauchlan sand (Alba). The Captain field, which was discovered in 1977, is in the Lower Cretaceous Captain sand, and has the lowest API oil and highest in-situ oil viscosity of any currently producing UKCS field.

The source rock for all the heavy oil fields in the UKCS is thought to be the Jurassic Kimmeridge clay. The oils originated from the deeper Central Graben and migrated westward and up the prominent faults which bounded the graben area, into traps in younger rock, in the shelf areas. Washing by meteoric water during the migration of the oil through the long tortuous paths caused a reduction in the API gravity. However, the main cause of the low gravity is thought to be due to biodegradation. At shallower depths, and lower temperatures, the bacterial activity becomes more and more intense, giving heavier oils, resulting from the removal of lower molecular weight alkanes. A plot of reservoir depth versus API gravity for some typical North Sea discoveries with API gravity less than 25° from the Shetland Platform and Fladen Ground Spur is shown in **Fig. 3**. Some of these heavy oil fields have gas caps, probably as a result of the biodegradation process or a late gas charge.

Table 1 shows a summary of the oil accumulations in the UKCS that fall into the 'heavy oil' category. It can be seen that over 2.1 billion barrels of oil-in-place are being developed. Three fields, Clair, Mariner and Bressay have been actively appraised over the last few years. The total developable oil-in-place in these is around 2.7 billion barrels. Clair is different from the other heavy oil plays in that it is in a much older Devonian formation, having a very complex geology. The mapped oil-in-place in Clair is some 5.4 billion barrels, however only a more limited volume of oil in the "core" area is thought to be developable. All the other discoveries total up to around 2.4 billion barrels. Other undrilled prospects in blocks studied to date, would add a further 2 billion barrels or so. This would imply that a conservative total heavy oil in-place estimate for the UKCS is around 10 billion barrels. Blocks not worked on as yet can be expected to add to this total.

Table 2 shows a summary of the typical characteristics seen in the UKCS heavy oils, giving an indication of their marketability.

API and Reservoir Viscosity

Crude oils are usually characterised by their API oil gravity (a measure of surface density). However, the API gravity of the oil is not necessarily an indicator of its producibility, since from a sub-surface standpoint it is the oil viscosity, and to a lesser extent the density, at reservoir temperature and pressure that are the key fluid properties. Reservoir temperature and the GOR have a very significant influence on the viscosity of the live oil, so that oils with a similar API gravity can have very different viscosities in the reservoir. A low API oil at a deeper horizon may be easily producible, on account of its lower in-situ viscosity. A 10°F increase in reservoir temperature can result in an order of magnitude reduction in viscosity in the case of high viscosity oils.

The data in **Fig. 3** has been analysed using viscosity correlations to infer information about reservoir viscosities. Many of the available correlations for dead oil viscosity have been based primarily on North American crudes. Recently a new heavy oil viscosity correlation has been published¹, using data from selected North Sea viscous oil reservoirs. The correlation gives dead oil viscosity as a function of temperature and API according to:

$$\mu_{od} = 10^{(-.8021 \times API + 23.8765)} \cdot T^{(0.31458 \times API - 9.21592)} \dots (1)$$

By including data from further samples the correlation could be extended by using the Watson characterisation factor, as a means of adjusting the predicted viscosity depending on the degree of paraffinicity of the sample.

Fig. 4 shows the estimated viscosities of dead oil at reservoir temperatures as a function of API, corresponding to the data in **Fig. 3**. This shows that, for a given API, quite a wide range of viscosities (at least a factor of 10) can be encountered depending on the depth of the reservoir. In addition, dissolved gas will have the effect of reducing the in-situ viscosity, with saturated oil viscosities typically being a factor of 3 to 6 lower than the corresponding dead oil. This discussion highlights the importance of good measurements of reservoir temperature and GOR. In the more viscous oil reservoirs it can be difficult to obtain reliable measurements of GOR from vertical appraisal wells. The high drawdowns needed to achieve acceptable production rates may make it hard to collect good single-phase downhole samples, and the separation problems associated with heavy oils may make accurate surface measurements of GOR from short term tests difficult. In some cases, a horizontal appraisal well operating at low drawdowns may be needed to obtain sufficiently accurate data.

Reservoir Productivity

The basic productivity of a reservoir will be controlled by the reservoir geometry (primarily formation thickness and reservoir continuity) and the ratio of the permeability of the formation to the viscosity of the oil. As a first approximation, combinations of permeability-thickness and viscosity in the

same ratio will correspond to equivalent reservoir productivities.

Combinations of permeability-thickness and viscosity giving the same productivity are illustrated by the lines on **Fig. 5**. Data points are included from major first generation light oil fields, together with some of the recent viscous oil developments and fields under appraisal. From this it can be seen that many of the current viscous oil developments have similar productivity to existing light oil developments, because the fields have very high permeabilities that compensate for the increased viscosity. The primary reservoir development issue in these situations is the control of premature water or gas breakthrough through the use of horizontal wells. In contrast, the Captain and Gannet E developments are significantly more challenging, with a productivity index an order of magnitude lower than the other viscous oil fields under development, requiring the issue of productivity and sweep to be addressed to achieve a robust development plan.

Vertical and Horizontal Wells. **Fig. 5** highlights that reservoir productivity may be a key challenge that needs to be addressed. Many of the UKCS viscous oil fields are in high permeability unconsolidated sands, with very high vertical permeability across the full reservoir interval, (typically $k_v:k_h > 0.1$), making them good candidates for the application of horizontal well technology.

The flow rate for a well in STB/day can be expressed in the form:

$$Q = \frac{k_h h}{\mu_o B_o} J^* \Delta p \quad \dots \dots \dots (2)$$

where the productivity index, J^* , is in units of bbl.cp/(day.psi. md ft). For a vertical well with no skin this is given simply by:

$$J^* = 0.007078 / \ln(r_e / r_w) \quad \dots \dots \dots (3)$$

while for a horizontal well J^* is a more complicated function, involving the vertical to horizontal permeability ratio, reservoir thickness, well length, well radius and drainage area. Renard and Dupuy have derived an equation to estimate J^* for a horizontal well². As an example, **Fig. 6** compares the productivity coefficient for a vertical well and different length horizontal wells in formations with thicknesses of 50, 100, 150 and 200 ft, for a well with a drainage area of 140 acres (with a circular drainage area for the vertical well and an elliptical region for the horizontal well), a $k_v:k_h$ of 0.5 and a well bore radius of 0.25 ft. For long horizontal wells theoretical productivity enhancements up to a factor of 30 are predicted, compared to the vertical well productivity coefficient. In low productivity reservoirs, the use of horizontal wells can dramatically reduce the number of wells required to meet the initial oil plateau rate. For example, in the Captain field at least 50 vertical wells would be required to obtain the plateau rate of 60,000 BOPD, compared to 5 horizontal producers.

Taking 10,000 bbl/day as the oil rate required from a single well in a typical development scenario, and assuming a

maximum drawdown of 250 psi (taking into account the relatively shallow unconsolidated nature of the viscous oil reservoirs and the fact that many contain saturated oils), using the results of **Fig. 6** shows that with vertical wells the reservoir $k_h h / \mu_o$ needs to exceed approximately 50,000 md.ft/cp (assuming B_o is near 1 for viscous oil fields). Where long horizontal wells are deployed (6000 ft) the minimum $k_h h / \mu_o$ falls to approximately 5,000 md.ft/cp, (taking a productivity index enhancement of 10 compared to vertical wells, recognising that the inflow profile may not be uniform because of wellbore friction). These approximate limits for the application of different well technology are shown in **Fig. 5**. This highlights three categories of viscous oil reservoir from a productivity standpoint: those that can be developed with vertical wells, those requiring horizontal wells and those requiring even larger completion lengths through the application of multi-lateral well (MLW) technology or very closely spaced horizontal wells.

The low productivity of the more viscous reservoirs means that wells may not flow under test without artificial lift.

Case Histories - Fields in Production

In this section the focus is on the UKCS heavy oil fields that are currently in production, to try and highlight the areas where lessons have been learnt, and the ways in which costs and risks have been managed. As seen in **Table 1**, the heavy oil fields in the UKCS that have proceeded to development so far, are those having in-situ oil viscosity below about 20 cp, except in the case of Captain, which has an in-situ oil viscosity of about 88 cp.

In the early days, when these heavy oil plays were being discovered and appraised, the wells were vertical, or at a moderate angle to the vertical. In most cases, high enough oil rates could not be achieved and sustained for long enough to justify commercial development. The key impetus to the exploitation of these heavy oil reserves can be attributed to the advances made in horizontal drilling. Horizontal completions will minimise pressure drawdown and maximise stand-off from the oil/water contact, thus achieving much higher productivities compared to a vertical well. These reservoirs are relatively shallow, hence exceptionally high offset/TVD ratios need to be achieved. The extremely high vertical permeability in these sands makes the onset of water coning into the horizontal wellbore one of the key criteria in the well design. The well track needs to be as close to the top of the reservoir as possible, to optimise recovery. If there is a gas cap as well, then an optimal stand-off from the gas cap needs to be maintained. Measurement while drilling, and modern well steering techniques, make the siting of horizontal wells, to the required tolerances, possible. Wells with stepout, from the drilling centre, of up to 13,000 ft and horizontal sections going up to 6000 ft in length, have been utilised in these fields.

Due to the unconsolidated nature of these formations, sand control measures are essential in the design of the completions in the production and water injection wells. The commonly

used completions have pre-packed screens for sand exclusion. Other methods, such as gravel packs with wire wrapped screens, have also been used.

Waterflooding is the main recovery method. On account of the adverse mobility ratio, water breakthrough occurs early, and a large portion of the reserves will be recovered at high watercut. Full voidage replacement, by injecting water into the aquifer, is implemented right at the outset, to maintain reservoir pressure and hence the lift capability in the producing wells. It is particularly important in the case of reservoirs with gas caps, to prevent the expansion of the gas cap towards the producing wells. All these fields need some form of artificial lift to maintain sufficiently high production rates. This could be in the form of ESPs, hydraulic pumps or gas lift. Permanent bottomhole pressure gauges are usual for these wells, especially if ESPs are used. This is mainly to optimise ESP performance, but also to provide pressure data for reservoir monitoring purposes.

As these fields produce large quantities of water, and the separation of water from the relatively heavy crude is not straightforward, considerable uncertainties will be inherent in the design of the process equipment, and the selection of the appropriate chemicals for de-emulsification, de-foaming and so on. The ultimate bottom line is that the export crude has to be within the specified water content limit, and the produced water needs to be de-oiled to less than 40 ppm oil content. The oil/water separation process may be simulated in a flow loop in the laboratory, if a sufficiently large oil sample is available. An extended well test (EWT) in an appraisal well will provide an opportunity to test out the process design and equipment.

Development risks will be significantly reduced if the long term productivity, and the water production (and gas coning, if applicable) behaviour is tested by conducting an EWT with a prototype field development well, prior to the development decision. The results of such a test can be used to confirm or adjust the reservoir parameters used in the simulation model, such as k_v , k_h , relative permeability characteristics and so on. A prototype production well at the appraisal stage would also enhance drilling experience and highlight any drilling risks involved in siting long horizontal wells to tight tolerances. An EWT is usually over a three month period. This length of testing would be sufficient to test and optimise the process facilities, and to evaluate the performance of the ESP and the gas lift option, and the performance of the completion. If water has not broken through during this time, it is usual to inject simulated formation brine, using coiled tubing, to simulate water coning to clarify separation issues. Lastly, the quantity of oil collected during an EWT could be used to test out its marketability, and of course, to try and recover all or part of the cost of the test.

In the development scheme that is selected, the costs and risks may be managed by proceeding in a phased manner. The philosophy is to avoid loading too much capital expenditure up front, and to ensure sufficient cashflow from the first phase before committing to expenditure on the next, and so on. The

following brief descriptions of some producing UKCS heavy oil fields should provide a flavour for the types of philosophies that have been adopted:

Harding.^{3,4} The field consists of four stratigraphically separate pools, Harding Central, Harding South, Harding North and Harding Northeast. The Development Plan initially commits to developing the Central and South pools, containing a total stock tank oil initially in place (STOIIP) of 322 MMSTB. **Fig. 7** shows the top structure map of these two pools. The main reservoir sands, in the Eocene Balder formation, are extremely homogeneous, having very high porosity and permeability. Both accumulations have gas caps. However, the gas caps are offset towards the east, as shown by the cross section in **Fig. 8**. Thus some producing wells can be sited to avoid gas coning. In general, to delay the onset of gas breakthrough, the horizontal production wells are completed with an optimal stand-off of some 75 ft from the GOC. The PI of each horizontal well is estimated to be in excess of 1000 BOPD/psi, implying that the drawdown in a typical well will be just 10 psi.

The two pools are developed using ten horizontal production wells, three water injection wells, and one gas injection well in Harding Central - all drilled from one drilling location that is central to both pools. In addition, two water supply wells are drilled into an aquifer in a shallower formation. This is because there is a risk of severe scaling problems, due to Barium Sulphate deposition, if seawater is used for injection. Produced water will be re-injected after treatment. The excess gas is injected into the Harding Central gas cap for future offtake. The development facilities are based on a permanently installed heavy duty jackup platform, with production and drilling facilities. The jackup sits on a concrete base, which also contains storage tanks for oil. The facilities can handle a peak production rate of 85,000 BOPD, and up to 140,000 BWPD of produced water. Oil export is by tankers.

The main impetus that pushed this development forward was the success with the 1000 ft horizontal appraisal well drilled and tested with an EWT in 1991. This confirmed the feasibility of developing Harding Central and South using horizontal wells, drilled from a central location. Harding began production in April 1996.

Gryphon.⁵ This field is in effect a sister field to Harding, being in the same locality and in the same formation, and having similar reservoir characteristics, including the presence of a gas cap. As such, the success of the Harding horizontal appraisal well was of benefit to Gryphon too. As in Harding, the development scheme for Gryphon depends largely upon horizontal wells. A total of eight horizontal producers, three water injection wells, and two aquifer supply wells, all drilled from a subsea wellhead cluster location, are utilised.

The field is produced through a purpose built floating production and storage and offloading facility (FPSO) based on the Tentech 850C design. It has 60,000 BOPD oil capacity, 77,000 BWPD produced water handling capacity and 79,000

BWPD water injection capacity. The low abandonment costs and the resale value of the FPSO significantly improve the economics of this development. Gryphon began production in October 1993. It demonstrated the feasibility of using low sulphate aquifer water for injection.

Alba.^{6,7} The reservoir consists of a stratigraphic trap where the mid Eocene Nauchlan sands, up to 400 ft thick, are sealed on all sides by shales. The STOIP is estimated at greater than 500 MMSTB. The system has a limited aquifer, having a pore volume similar to that of the oil zone, with the water leg increasing in thickness towards the south. The Nauchlan sands are generally clean and have high permeability. However, interbedded allochthonous shales have been encountered in several wells. These are thought to be 'stringer' shales, and are not expected to effect recovery, but impact the drilling of horizontal wells, making a sidetrack necessary if the well path goes through too much of it.

The total well count as currently planned, has 24 producers and 7 water injectors. Alba has no gas cap. Hence, the optimal placement of the horizontal wellbore is close to the top of the reservoir, away from the OWC. MWD and wellsite biostratigraphy have helped in achieving the optimal trajectory in these wells. The water injectors are completed in the water leg at the base of the reservoir, and the recovery mechanism is expected to be an efficient, bottom up, water drive. Full voidage replacement is being implemented to maintain reservoir pressure. Artificial lift will be by installing ESPs in all the producers. The injection water is seawater, and the produced water is not re-injected.

The main uncertainties in Alba were the mapping of the Nauchlan sands, and hence the STOIP, and predicting the watercut behaviour and hence oil rates. The latter would impact on the sizing of the separators and process equipment. The original plan had a platform (drilling, processing, accommodation) in the north of the field to develop the 'core area', during phase 1. This was to be followed by a second, similar, platform some 6 km to the south, in the second phase. Operating experience and reservoir performance from phase 1 was vital for the optimisation of phase 2. With ERD wells it is possible to reach all of the southern producing well locations, obviating the need for the southern platform. By retrofitting additional processing equipment on the northern platform, it is possible to handle the total liquid handling requirements. The upgraded capacities are 100,000 BOPD (continuous) for oil, 390,000 B/D for gross liquids and 400,000 BWPD water injection.

Gannet E. The reservoir consists of a low relief anticline in the Palaeocene Forties formation, with around 225 ft of gross oil column. The sand is of excellent quality. Gannet E is one of the Gannet cluster of accumulations (A, B, C, D, E, F), which have the central processing facilities (Gannet Alpha) located at Gannet A. Gannet E is a more recent add-on to the complex,

and it is the only one with heavy oil. Gannet E production is exported through the existing Gannet evacuation system.

The field is developed as a subsea tie-back to Gannet Alpha, which is 14 km away. Due to the high viscosity of the oil it is a significant technological challenge to develop Gannet E in a cost effective manner. The development is in two phases. Phase 1, which is currently ongoing, has one 2800 ft horizontal well. It has a pre-packed screen in the completion, and an ESP to provide lift. It is the first subsea development in the UKCS to use ESP technology. The expectation is that water injection will not be required, as the large regional Forties aquifer would provide a strong natural water drive. Operational experience from phase 1 will be essential to better define phase 2, which may require a further two or more horizontal producers. In addition to the reservoir uncertainties, operational uncertainties such as the performance of the ESP, how the separators at Gannet Alpha will handle the heavy crude, and how the high viscosity emulsions that will be produced when water production commences, are going to be handled, need to be fully assessed.

Captain.⁸ This field falls into a different class from the above as the in-situ oil viscosity is much higher and the waterflood recovery is affected much more by the adverse mobility ratio. The reservoir is in unconsolidated lower Cretaceous, high porosity, high permeability sandstone. **Fig. 9** shows the hydrocarbon accumulation map of the field. The development scheme has to be based on horizontal producing wells. The reservoir depth is relatively shallow at 2900 ft TVDSS. To exploit all of the field, wells have to be drilled from two drilling centres.

An EWT with a prototype horizontal well was conducted successfully in 1993, prior to the development decision⁹. The results of this significantly reduced the development risks. It was decided to go for a staged development to minimise initial capital investment and to gain valuable operational experience, prior to the next phase. The initial development area is denoted as area A in **Fig. 9**. The first phase, installed in January 1997, consists of a FPSO and a wellhead platform at the area A drilling centre. The FPSO is capable of processing 65,000 BOPD oil and 230,000 BWPD produced water. The produced water is re-injected, along with make up water from an underlying aquifer.

The second phase of the development is to access the reservoir in eastern area B. For this phase the capacity of the production facilities need to be upgraded to 100,000 BOPD oil and 400,000 BWPD produced water. The scheme to achieve this is to install additional processing capacity on a new platform, bridge linked to the area A wellhead platform, and access area B by drilling wells from a subsea centre, with a flowline bringing the commingled flow to the area A processing facilities.

According to the current simulation model, area A will need 21 producing wells and 6 water injectors, and area B will need 12 producing wells and 3 water injectors, during the life

of the field. **Fig. 10** is a cross section showing a typical horizontal producing well in Captain. It shows the several sidetracks that were necessary to keep the well track close to the top of the reservoir. Horizontal lengths in excess of 6000 ft have been achieved in some these wells. Area A producing wells have ESPs for artificial lift, while hydraulic submersible pumps are planned for area B. Oil rates of 15,000 BOPD have been achieved in some of these wells, and gross fluid rates up to 21,000 B/D.

The use of polymers to augment the waterflood has been actively evaluated for Captain¹⁰. A pilot scheme for a localised area is being considered. The final go ahead for this will of course depend on the prevailing economics.

Case Histories - Fields in the Appraisal Stage

There are many UKCS heavy oil fields that are still under appraisal, the most prominent being Clair, Mariner and Bressay. These have been worked fairly actively, until around mid-1998, when the slump in the price of oil began to have a negative impact on the economics driving new developments. However, to complete the story on the development of heavy oils in the UKCS, and to perhaps provide some clues as to the possible future of these heavy oils, it would be appropriate to provide some description of the work that has been done to evaluate these fields.

The key criterion that would propel any of these fields to a development phase is positive economics with a primary or a cold waterflood recovery scheme, even though recovery factors may not be high. While waterflooding is extensively used in the offshore environment in the UKCS, and the risks are well understood, there is very limited offshore experience of more advanced methods, such as thermal processes for viscosity reduction, or chemical methods such as polymer injection for improving conformance. To manage risk these will have to be subsequent 'add-ons' to the baseline cold waterflood scheme, if the IOR scheme is shown to be successful via a pilot project. The Captain field will provide a good example of this, if the polymer pilot goes ahead.

As stated earlier, Clair¹¹ is in an older (Devonian) and deeper formation. The sands have a much lower permeability, and achieving economic flowrates depends on natural fractures, or artificial stimulation, even with horizontal wells. As such, Clair belongs in a category of its own, and will not be elaborated any further in this paper.

Mariner. This field has two Palaeocene hydrocarbon bearing zones. The upper reservoir is in the Heimdal sand, having a very heavy 540 cp in situ viscosity oil. The lower reservoir is in the Maureen sand, with 65 cp oil, and underlain by a large aquifer. Neither reservoir has a gas cap. **Fig. 11** shows a log cross section containing these two horizons.

The Maureen reservoir was being considered for the first phase of a development scheme, as reasonable flowrates and recoveries could be achieved by a cold waterflood. Simulation studies have investigated schemes that utilise long horizontal

wells (6000 ft) or multilateral wells (3000 ft). The economics of drilling long, large diameter horizontal wells at such shallow depths brings such schemes into serious consideration. Most of the oil is recovered at high watercut. Plateau oil rate of 60,000 BOPD and total liquid production rates of up to around 350,000 B/D are assumed. The operator also had studies performed to investigate thermal methods for Maureen, but these were found to be uneconomic due to the large underlying aquifer.

A 90 day EWT was conducted using a prototype development well. It is worth mentioning that the drilling of this well pushed drilling and completion technology into new areas. One was the drilling of 5749 ft of 12 1/4" horizontal hole entirely in the Maureen reservoir. However, plugging of the 9 5/8" pre-packed screens limited production rates and, subsequently, an 8 1/2" sidetrack was drilled, having 4004 ft of horizontal section in the Maureen. This was completed with 5 1/2" screens and subsequently externally gravel packed. A 30,000 B/D ESP, with variable speed drive was used. The EWT was a success, yielding valuable experience in drilling, completion, production and processing. Elaborating any further on this will be beyond the scope of this paper.

The overlying Heimdal reservoir was intended to be developed in a subsequent phase. The key uncertainty in Heimdal is the mapping of the sand, primarily due to the poor seismic imaging of the Heimdal sequence. The further appraisal of Heimdal could proceed 'piggy back' with the development of Maureen, perhaps using the same wells.

The operator has had several studies performed to investigate thermal methods for Heimdal. These were steam and hot water flooding, and steam assisted gravity drainage (SAGD). SAGD is the most operationally complex, but yields high recoveries. The success of a SAGD process for Heimdal however depends on the presence and size of connected aquifer.

Bressay. This field has the heaviest oil (11⁰-12⁰ API, 1000 cp in situ oil viscosity) of all the fields discussed so far. It is in the Hermod and Dornoch sands in the Sele formation, with about 265 ft maximum oil column, a small gas cap, and a potentially large and effective aquifer. **Fig. 12** shows the top structure map. The permeability is in the 10 darcy range. Four conventional appraisal wells have been drilled in the formation. DSTs conducted in these, with ESPs for artificial lift, had flowrates ranging from 200 to 2800 BOPD.

The thrust has been to demonstrate that an economic development can be achieved with a cold water flood as the baseline scheme. Simulation studies have considered long (6000 ft) horizontal wells, bilateral wells and trilateral wells, with water injection to ensure 100 % voidage replacement from the outset. Well spacings from 30 to 60 acres have been tried. It has been highlighted that the frictional losses along the long horizontal wellbore is a factor to consider in the design of the scheme. A further appraisal well or two need to be drilled, and an EWT, on similar lines to those conducted in the fields

discussed above, needs to be carried out, before sufficient confidence can be gained, to proceed to a development.

A range of tertiary recovery techniques have been simulated with Bressay. These are the injection of polymer, hot water injection, gas injection, steam injection and in-situ combustion. Steam injection gave the highest recovery, while in-situ combustion came next.

IOR Techniques

This section discusses the scope for application of IOR techniques to overcome some of the problems caused by low productivity and poor sweep. The technical and economic viability of IOR methods needs to be carefully examined on a case by case basis.

Multilateral Wells. The application of multi-lateral well technology could reduce the number of wells required in very low productivity fields, increasing the economic viability of these developments. However, a key requirement for the successful application of MLW technology is the capability to control the offtake rate from individual laterals. Without this, the lower drawdowns required to achieve a given flow rate as water breaks through, would mean that an increasing volume of fluid would be produced from the first lateral cutting water, at the expense of the other laterals. The option of completely shutting off the offending lateral would not be acceptable, since a significant fraction of the recoverable reserves are produced after water breakthrough, with wells typically needing to produce for extended periods at high water cuts.

Downhole Separation. Downhole separation with the disposal of water downhole can improve oil recovery in circumstances where production is facilities constrained. Hydrocyclones are used to separate off a purified water stream and downhole pumps to provide the power to produce fluids to surface and to pump excess water into a disposal zone.

In viscous oil applications separation difficulties may arise because of the small density difference between the oil and water and because high bulk fluid viscosities can arise through the formation of emulsions at intermediate volume fractions of oil and water. The high viscosities constrain the practical range over which concentration of the oil in the produced fluid is possible. However, even removing half the water downhole from a well producing at 90% watercut allows increased oil production (with the watercut decreased to 82%). The reduction in fluid production to surface provides an alternative to expanding the existing free water knockout capacity, however this is at the cost of installing more complex equipment downhole and providing an appropriate water disposal route in each well.

Polymer Flooding. Where waterflood displacements are viscous dominated the reservoirs are potential targets for the classical application of polymer flooding to reduce the local effective residual oil saturation by changing the fractional flow

curve and to improve sweep in less permeable zones. However, polymer flooding can also be effective in gravity dominated viscous oil reservoirs¹². In the absence of underlying water, injected water slumps and channels along the base of the reservoir before coning into the producer. In polymer flooding, the ratio of viscous to gravity forces is increased, reducing the slumping and improving vertical sweep in the reservoir. Even in the presence of an underlying aquifer (provided the thickness is no greater than the thickness of the oil column), polymer flooding can still be effective, by restricting water channelling through the aquifer.

The viscous oil reservoirs are shallow enough for the temperature to be low enough for biopolymers to have sufficient thermal stability to be applicable. The best candidate for polymer flooding identified to date is Captain. The low formation water salinity and hardness makes polyacrylamide (PAM) injection feasible. This has logistical advantages since PAM can be delivered to the platform in the form of high concentration liquid emulsions or dispersion products. From a sub-surface standpoint, PAM has the advantage compared to biopolymers of producing a residual resistance factor (RRF) associated with adsorbed polymer. This can provide a long term reduction in permeability in flooded zones after the mobile polymer has been swept through the reservoir, further increasing recovery. The presence of an RRF is particularly beneficial in regions of the reservoir underlain by water.

Gas Injection. Gas injection into a primary gas cap, where this exists, may provide an alternative strategy to water flooding, giving lower effective residual oil saturations (because of the much greater density contrast between oil and gas compared to that between water and oil). Recent measurements¹³ of oil gravity drainage relative permeabilities in sandpacks with permeabilities representative of UKCS viscous oil fields, have shown that relative permeabilities are independent of viscosity over the range 2 to 200 cp and higher than those found in consolidated outcrop sandstone. The effective residual oil saturation over a range of viscosities and injection rates have been calculated, under appropriate conditions effective saturations of ~10% may be obtained for oils of 100 cp.

Thermal Methods. Increasing temperature can significantly reduce the oil viscosity. This section discusses the potential for thermal methods, recognising the limitations that offshore operations might place on project feasibility.

Hot water flooding. Even if specific hot water injection facilities are not provided on the platform, hot water may be available as a by-product of the separation process. The displacement mechanisms associated with hot water flooding are complex, with even the density difference between reservoir brine and the injected hot water being important in some circumstances¹⁴. A potential problem with hot water flooding is the unstable nature of the displacement, triggered by the unstable miscible displacement between cold and hot

water¹⁵. Studies of the potential for hot water flooding to improve recovery have been undertaken for a range of fields¹⁶.

For moderate temperature fields with oil viscosities around 10 cp (e.g. Alba, Gryphon and Harding), hot water flooding makes little difference to recovery in the absence of underlying water, but reduces recovery in the presence of limited thicknesses of underlying water¹².

Studies in Captain (typical of low temperature fields with oil viscosities around 100 cp) suggested that there was no significant benefit from hot water flooding. Depending on the details of the scenario considered (e.g. production rate, $k_v:k_h$) there could be a marginal benefit (+0.7% STOIP) to a small reduction in recovery (-2.6% STOIP). In cases where an increment was found, there was a long delay between the start of the hot water injection and the production of incremental oil.

Conceptual studies relevant to low temperature fields with higher viscosities (~400 cp) and where the oil column is underlain by a thick aquifer, have shown systematic benefits from hot water flooding, up to 18% STOIP. However, the results were very sensitive to $k_v:k_h$, which in turn impacts on the optimal position for the hot water injector.

Steam Injection. Steam injection is a highly successful IOR method for onshore shallow heavy oil fields. Given the depth of the higher viscosity UKCS viscous oil fields (3000-5000 ft), steam flooding is only likely to be economically feasible if the reservoir pressure is significantly reduced prior to steam injection. This rules out reservoirs with significant aquifer pressure support as candidates.

Simulation studies in typical pattern elements show that steam flooding has the potential to double recovery compared to water flooding, provided gravity forces are utilised to control the steam front. This means operating in a SAGD type mode, or by injecting steam into a depleted primary gas cap, where this is present, and using horizontal production wells placed low in the oil column.

Even if the facilities issues associated with offshore steam generation and injection can be overcome, it may be difficult to implement a steam flood, since the well positions required for a basic water flood may be quite different from those needed for a steam flood.

In-situ Combustion. Air injection provides an alternative to hydrocarbon gas or nitrogen injection, with potential benefits from reduced gas costs and lowered effective residual oil saturations. The same overall considerations relevant to gas injection apply, with additional concerns including the effect of breakthrough of corrosive combustion products on the production facilities and well casing integrity in the combustion zone.

Future Directions for UKCS Heavy Oil Developments

It is fortunate that UKCS heavy oils generally occur in the shallow, younger sands that are clean and of high permeability. This, together with the advances made in horizontal drilling, completion and sand control technology, has allowed operators

to achieve production levels that have made commercial developments possible. Harding and Gryphon were outstanding achievements when they came onstream. At the time Harding had one of the lowest development costs per barrel in the UKCS³. The Captain field, which came onstream in March 1997, set another milestone by demonstrating the attractiveness of developing even more viscous fields.

Until recently, very active appraisal work on fields with yet more viscous oils, Mariner (65 and 540 cp) and Bressay (1000 cp) has been ongoing. As with other appraisal activity, work on these fields has slowed down at present. However, there is some degree of optimism shown by the industry at large, as regards the longer term future of UKCS heavy oils. This has been apparent in the interest shown in licence blocks in the heavy oil areas in the UKCS.

The industry is continuing to look for innovative and aggressive ideas for driving down costs (finding, development and operating costs on a per barrel basis). This has to be achieved within the context of the new environmental regulations that are being put in place. A general, industry led, cost reduction initiative, termed CRINE (Cost Reduction Initiative for the New Era) has been going on for a few years. This has resulted in about a 30% reduction in costs of oil and gas projects. CRINE has been superseded by CRINE NETWORK, which is committed to making the UK oil industry competitive anywhere in the world. Heavy oil developments should have the scope for even more innovative ideas. Some areas to focus on, to reduce capex requirements, would be the following:

- Improved reliability of sand control equipment, ESP life and so on.
- Reduction of produced water volumes to surface - well type, location, designer wells, smart well completions, downhole separation, polymers to reduce mobility ratio, and so on.
- Facilities sharing - joint development of more than one field may prove economic, where the development of each individual field is uneconomic. For example, the main processing facilities could be located at the field with the heaviest oil, while the less viscous crudes can be pumped to it by pipeline (possibly with some partial subsea processing). Other facilities such as drilling support, injection water, electrical power, fuel gas, operational logistics and so on, can be shared.

Finally, the marketability and future demand for these crudes needs to be thoroughly researched. In general, these heavy crudes cannot be sold on the spot market. They are sold direct to buyers, usually at a small price discount from the Brent marker price. UKCS heavy oils are generally low in Sulphur, but some may be higher in acidity. Higher acidity crudes may be used for blending with other crudes, paying a price penalty. The economics of removal of the acidity, to restore the value of the crude, could also be looked at. Some of the heavy crudes may be sold as "lube oil" crudes, or as fuel oil bypassing any refining stage. In such cases the crudes may even command a small premium.

Conclusions

1. Significant momentum has been generated in developing UKCS heavy oils, and this is reflected by the interest shown by operating companies in heavy oil license blocks.

2. Continued cost reduction and technology innovation will help to maintain this level of activity.

3. The excellent quality of many of the reservoirs partly offsets the higher viscosity of the oil. Horizontal wells provide the means to manage the effects of water and gas coning, and sufficient well productivity in the lower productivity fields.

4. It is important to research the long term market for these crudes to maximise the price achieved with respect to marker crudes.

5. Heavy oils represent a significant potential resource base on the UKCS, with around 10 billion STB in place. The recovery factor will depend on the development schemes used. Assuming an average recovery factor in the range 20 to 40% shows that there are approximately 1.5 to 3 billion STB to be produced over and above that from existing UKCS heavy oil developments.

Nomenclature

- B_o = oil formation volume factor
 h = reservoir thickness, ft
 k = permeability, md
 J^* = productivity index, bbl.cp/(day.psi.md.ft)
 Q = production rate, bbl/day
 T = temperature, °F
 Δp = pressure drawdown, psi
 r_e = radius of well drainage area, ft
 r_w = radius of well, ft
 μ_o = reservoir viscosity, cp
 μ_{od} = dead oil viscosity, cp

Subscripts

- h = horizontal
 v = vertical

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TABLE 2 - OIL CHARACTERISTICS/QUALITY

Field	API^o	Sulphur (wt %)	TAN (mgKOH/g)	Wax (wt%)	Pour point (°F)	Asphaltene (wt%)
Alba	20	1.3	1.6	1.0	-13	1.0
Captain	19	0.7	2.5	trace	-26	0.3
Gryphon	21	0.4	4.5	0.1	-45	0.1
Harding C	19	0.6	3.1	0.7	-17	0.35
Harding S	21	0.5	2.8	<0.1	-44	0.2
Gannet E	20	0.8	1.2	2.5	10	0.85
Mariner M)	14	1.1	4.1	nil	20	1.9
Mariner (H)	12	1.4	5.5	nil		1.6
Bressay	11-12	0.8	8.0	not measureable	45	1.2
Clair	25	0.5	1.2	4.5	-4	0.85

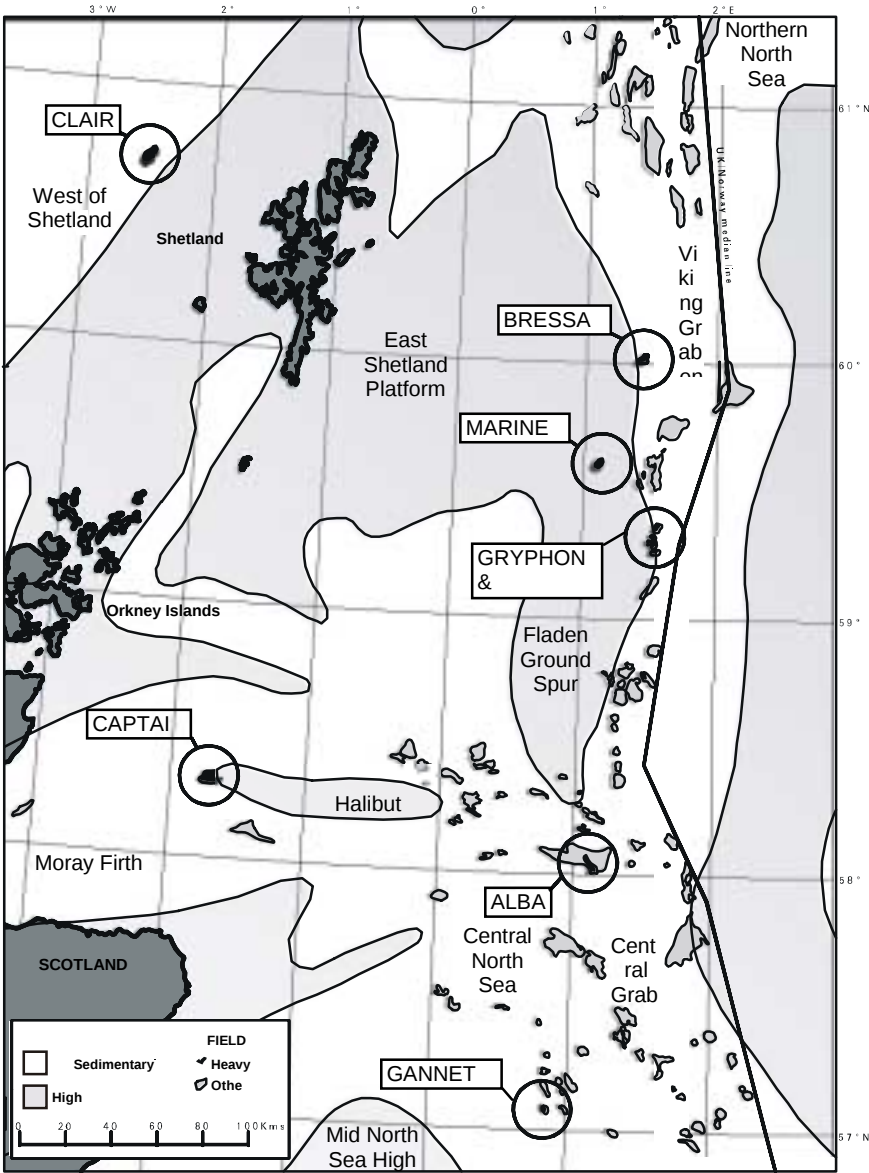


Figure 1: - Major structural elements in the Central and Northern North Sea and location of major heavy oil accumulations in the UKCS currently under development or appraisal.

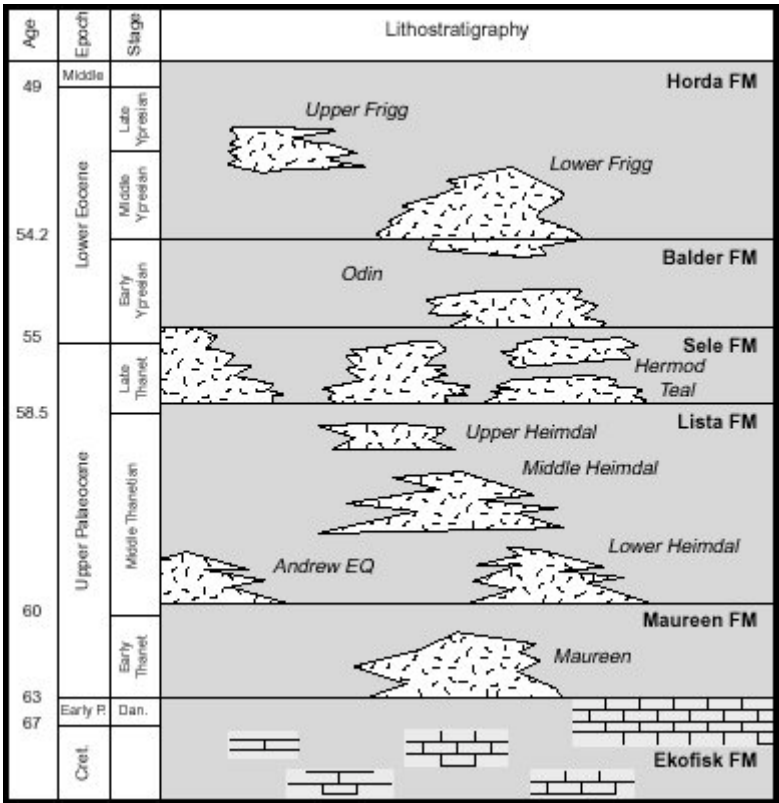


Figure 2: - Lower Tertiary stratigraphy of Northern North Sea.

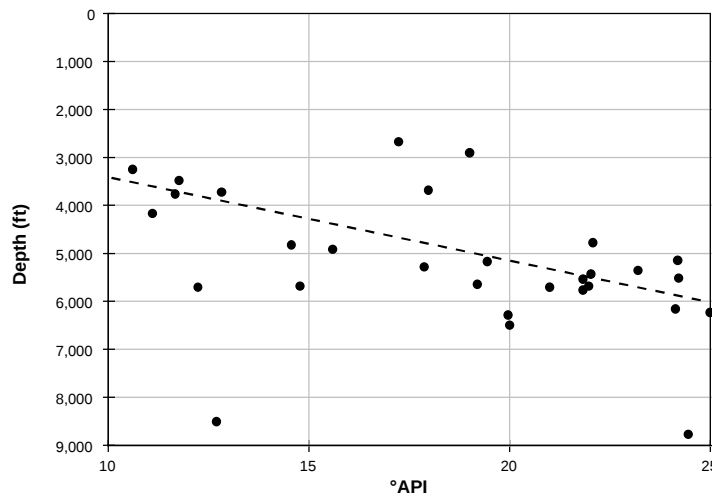


Figure 3: - Reservoir depth vs. API gravity for North Sea discoveries with API gravity less than 25° from the Shetland Platform and Fladen Ground Spur.

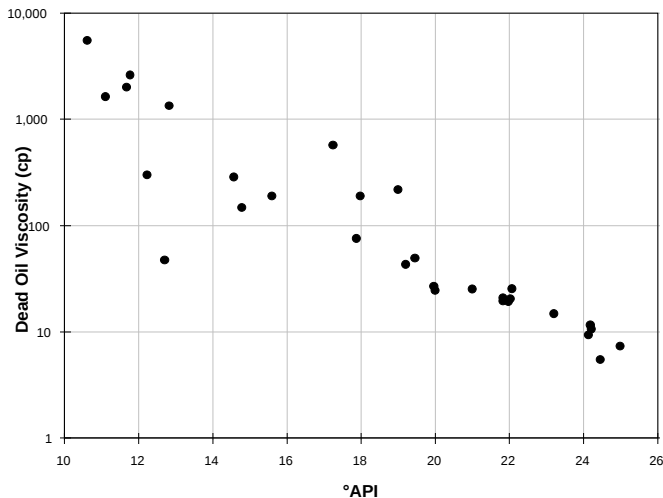


Figure 4: - Estimated viscosities of dead oil at reservoir temperature as a function of degrees API

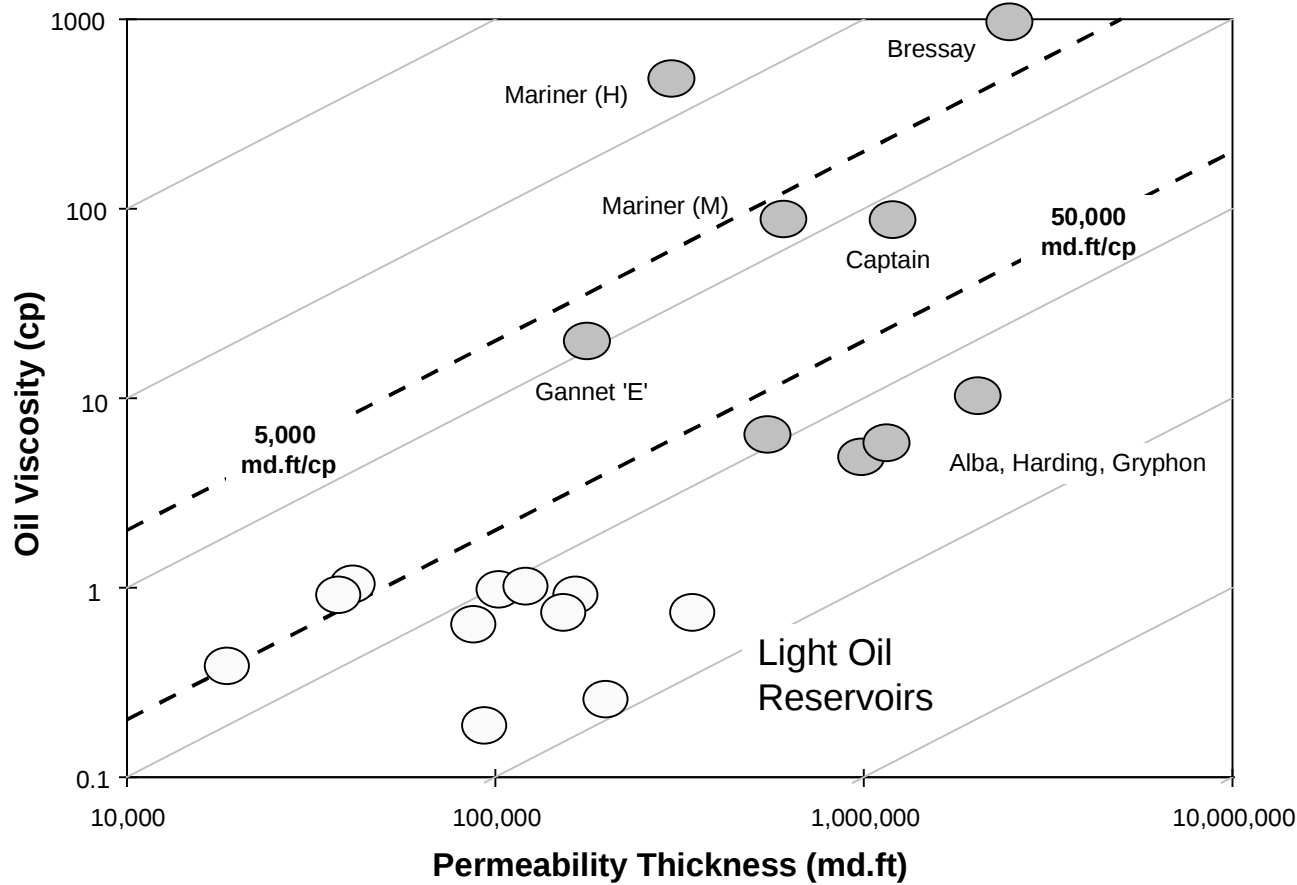


Figure 5: - Viscosity plotted against the permeability thickness product for heavy oil fields and representative light oil fields, showing fields with equivalent productivity.

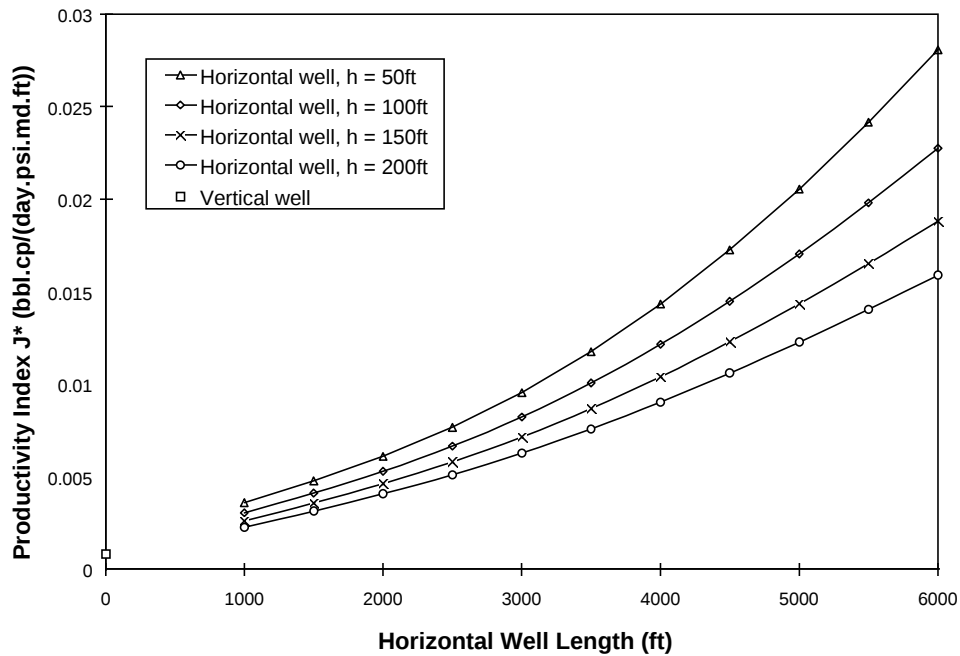


Figure 6:- Productivity index for vertical and horizontal wells

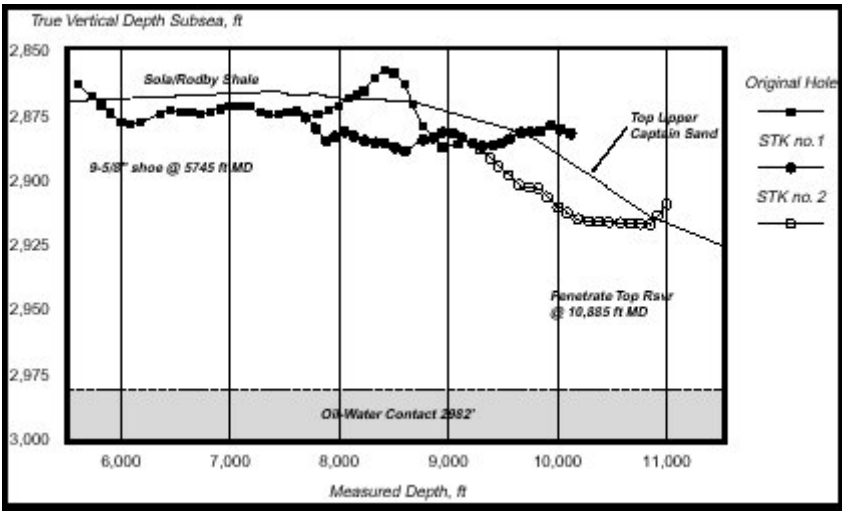


Figure 10: - Captain field: cross-section showing trajectory of typical area A development well

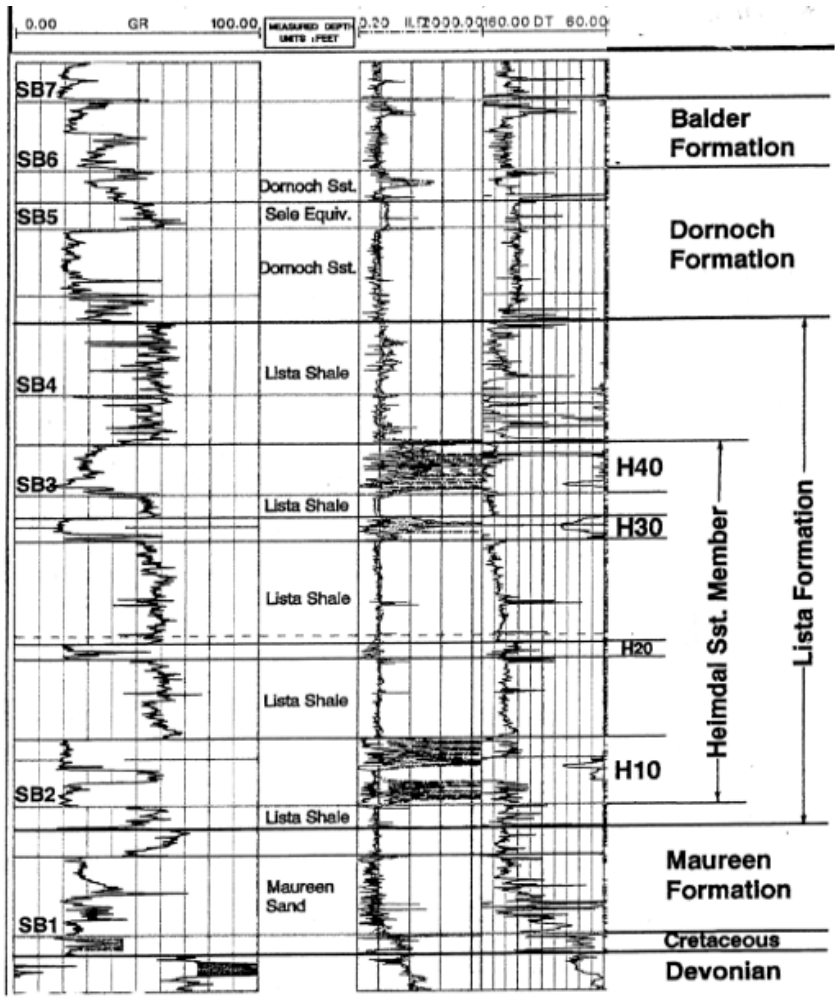


Figure 11: - Mariner field: type log.

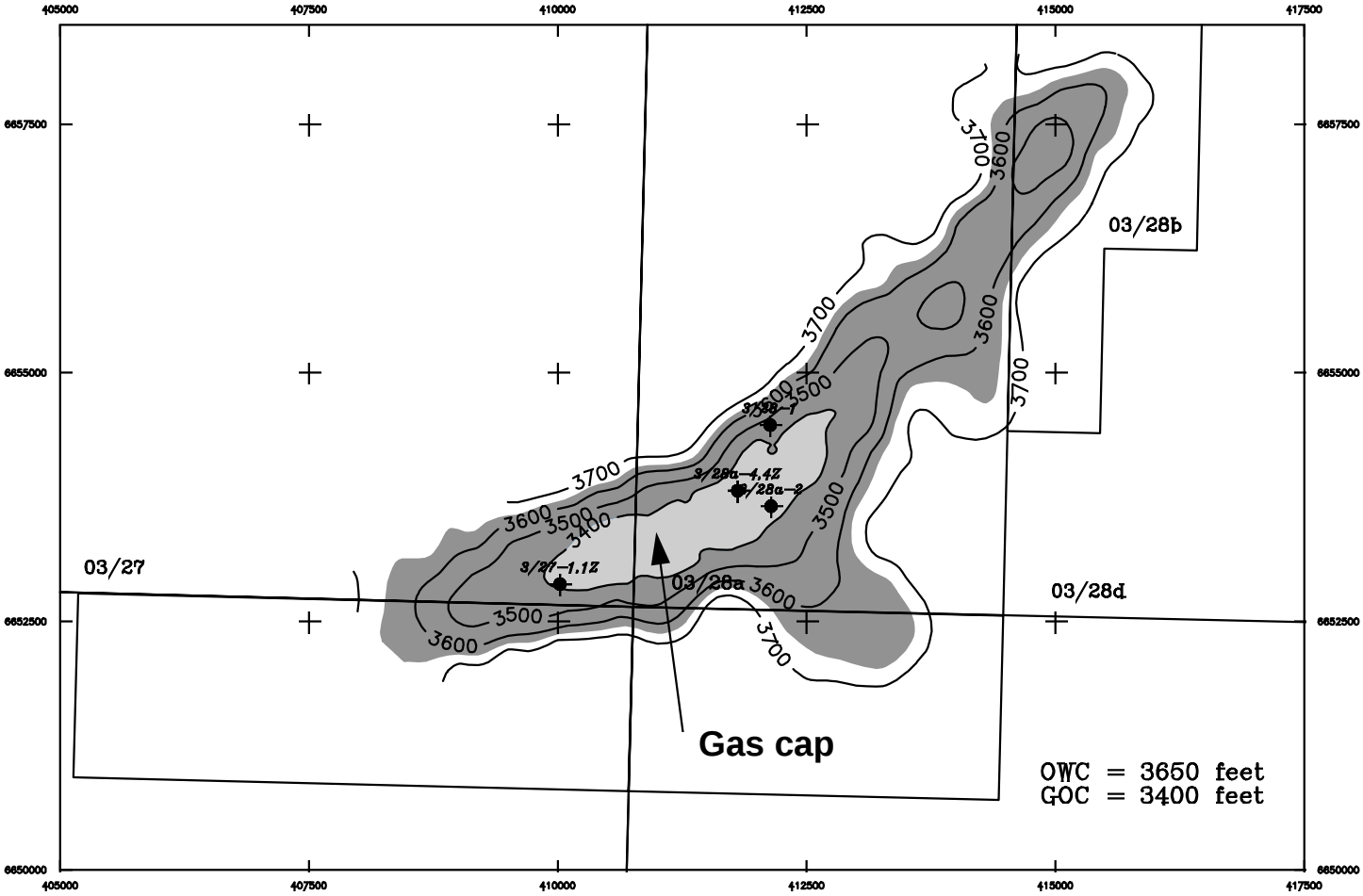


Figure 12: - Bressay field: oil isochore